Economic and Threshold Analysis
For
Proposed 43 CFR Subpart 3175
Measurement of Gas from Federal and Indian Oil and Gas Leases

Introduction

By statute and executive order,[1] an agency proposing a significant regulatory action is required to provide a qualitative and quantitative assessment of the anticipated costs and benefits of that action. Executive Order 12866 requires agencies to assess the benefits and costs of regulatory actions, and for significant regulatory actions, submit a detailed report of their assessment to the Office of Management and Budget (OMB) for review. A rule may be significant under Executive Order 12866 if it meets any of the following four criteria:

- Has an annual effect on the economy of $100 million or more or adversely affects in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

- Creates a serious inconsistency or otherwise interferes with an action taken or planned by another agency;

- Materially alters the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

- Raises novel legal or policy issues arising out of legal mandates, the President’s priorities, or the principles set forth in the Executive Order.

Similarly, the Small Business Regulatory Enforcement Fairness Act (SBREFA) defines a major rule as one that:

- Has an annual effect on the economy of $100 million or more;

- Creates a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; or

- Has significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises in domestic and export markets.

If determined to be a major rule, the SBREFA requires an agency to prepare an analysis when issuing a proposed rule addressing whether the rule would have a significant impact on a substantial number of small entities.

The purpose of the economic analysis required under Executive Order 12866 is to provide information allowing decision makers to determine that:

[1] Executive Order 12866, Regulatory Planning and Review, the Unfunded Mandates Reform Act, and the Small Business Regulatory Enforcement Fairness Act.

- There is adequate information indicating the need for and consequences of the proposed action;
- The potential benefits to society justify the potential costs, recognizing that not all benefits and costs can be described in monetary or even in quantitative terms, unless a statute requires another regulatory approach;
- The proposed action would maximize net benefits to society (including potential economic, environmental, public health and safety, and other advantages; distributional impacts; and equity), unless a statute requires another regulatory approach;
- Where a statute requires a specific regulatory approach, the proposed action would be the most cost-effective, including reliance on performance objectives to the extent feasible; and
- Agency decisions are based on the best reasonably obtainable scientific, technical, economic, and other information.

To support this determination, this economic analysis contains the following:[2]

- A statement of the need for the proposed action;
- An examination of alternative approaches; and
- An analysis of benefits and costs.

The Regulatory Flexibility Act (RFA) requires agencies to analyze the economic impact of proposed and final regulations to determine the extent to which there is a significant economic impact on a substantial number of small entities. Executive Order 13272 reinforces executive intent that agencies give serious attention to impacts on small entities and develop regulatory alternatives to reduce the regulatory burden on small entities. When the proposed regulation would impose a significant economic impact on a substantial number of small entities, the agency must evaluate alternatives that would accomplish the objectives of the rule while minimizing any significant impact on small entities. Inherent in the RFA is a desire to remove barriers to competition and encourage agencies to consider ways of tailoring regulations to the size of the regulated entities.

Statement of Need

The Secretary of the Interior has the authority under various Federal and Indian mineral leasing laws to manage oil and gas operations on Federal and Indian (except Osage Tribe) lands. The Secretary has delegated this authority to the Bureau of Land Management (BLM), which has issued onshore oil and gas operating regulations codified at part 3160 of Title 43 of the Code of Federal Regulations (CFR). The operating regulations at 43 CFR 3164.1 authorize the BLM Director to issue Onshore Oil and Gas Orders when necessary to implement and supplement the operating regulations.[3] For Indian leases, unit participating areas (PAs), and communitized areas (CAs), the delegation of authority to the BLM appears at 25 CFR parts 211, 212, 213, 225, and 227.

This proposed rule would replace Onshore Oil and Gas Order 5 (Order 5) with a new regulation that would be codified in the CFR at new 43 CFR subpart 3175. Order 5 establishes minimum standards for ensuring that gas produced from Federal and Indian (except Osage Tribe) leases is accurately measured. The proposed rule would update these standards and requirements.

The BLM is proposing to replace Order 5 because it is more than 25 years old. Conditions, policies, procedures, requirements, and technologies have changed significantly since Order 5 was issued in 1989. The proposed rule is based on the BLM's own internal evaluation of its existing requirements, its field expertise in

[2] Office of Management and Budget, Regulatory Analysis Circular A-4, September 17, 2003 (http://www.whitehouse.gov/omb/inforeg/circular_a4.pdf).
[3] This section also states that all such Orders are binding on the lessees and operators of Federal and Indian (except Osage Tribe) onshore oil and gas leases, unit PAs, and CAs.

gas measurement, and the conclusions and recommendations contained in several outside studies and reports prepared by the Secretary of the Interior's Royalty Policy Committee, Subcommittee on Royalty Management (Subcommittee) in 2007, the Government Accountability Office (GAO) in 2010 and 2015, and the Department of the Interior Office of Inspector General (OIG) in 2010 (each of which is discussed briefly below). These entities recommended that the BLM evaluate its existing gas measurement guidance to ensure it reflects current technologies and standards and, where appropriate, update the guidance and regulations. Up-to-date measurement requirements are critically important because they provide the mechanism to ensure that gas produced from Federal and Indian (except Osage Tribe) leases is properly accounted for, thus ensuring that operators pay the proper royalties due.

The Secretary of the Interior appointed the Subcommittee to review the procedures and processes surrounding the management of mineral revenues. The Subcommittee also was commissioned to provide advice to the Secretary and other Departmental officials responsible for managing mineral leasing activities and to provide a forum for the public to voice their concerns about mineral leasing activities. The Subcommittee's *Report to the Royalty Policy Committee*, dated December 17, 2007, recommends, among other things, that the BLM strengthen its policies governing production accountability. Revisions are also needed, the report says, to take into account changes in technology and industry practices.

The Subcommittee determined that the BLM's production accountability methods are "unconsolidated, outdated, and sometimes insufficient." It highlighted the fact that the BLM policies and guidance have not been consolidated into a single document or publication. As a result the report found that the BLM's 31 oil and gas field offices use varying policy and guidance, some policy and guidance is outdated, and some policy memoranda have expired. The Subcommittee also found that some BLM State Offices have issued their own "Notices to Lessees and Operators (NTL)" for oil and gas operations. While such NTLs may have a positive effect on oil and gas field operations, they nevertheless lack a national perspective and may introduce inconsistencies among the States with respect to gas measurement activities.

The Subcommittee specifically recommended that the BLM evaluate Order 5 to ensure that it includes sufficient "guidance" for checking that proper royalties are paid on gas. In response, the Interior Department formed a Fluid Minerals Team, comprised of Departmental employees who are oil and gas experts. The team determined that Order 5 should be updated to reflect industry practices and technologies that have changed since 1989.

The proposed changes also address findings and recommendations made by the GAO (Report to Congressional Requesters, *Oil and Gas Management, Interior's Oil and Gas Production Verification Efforts Do Not Provide Reasonable Assurance of Accurate Measurement of Production Volumes*, (GAO-10-313) and Report to Congressional Requesters, *Oil and Gas Resources, Interior's Production Verification Efforts: Data Have Improved but Further Actions Needed*, GAO 15-39 (GAO 2015 Report)) and the OIG (Bureau of Land Management's Oil and Gas Inspection and Enforcement Program, CR-EV-0001-2009).

In 2010, the GAO found that the Department's measurement regulations and policies do not provide reasonable assurances that oil and gas are accurately measured because, among other things, its policies for tracking where and how oil and gas are measured are not consistent and effective (GAO 2010 Report, p. 20). The report also finds that the BLM's regulations do not reflect current industry-adopted measurement technologies and standards designed to improve oil and gas measurement (*id*.). The GAO recommended that Interior provide Department-wide guidance on measurement technologies not addressed in current regulations and approve variances for measurement technologies in instances when such technologies are not addressed in current regulations or Department-wide guidance (see *id*., p. 80). The OIG report made a similar recommendation in 2010 that the BLM, "[e]nsure that oil and gas regulations are current by updating and issuing onshore orders…." (see page 11). In its 2015 report, the GAO reiterated that "Interior's measurement regulations do not reflect current measurement technologies and standards," and that this "hampers the agency's ability to have reasonable assurance that oil and gas production is being measured accurately and verified . . ." (GAO 2015

Report, p. 16.) The GAO recommended, among other things, that the Secretary direct the BLM to "meet its established time frame for issuing final regulations for gas measurement." (*Id*., p. 32.)

The GAO's recommendations related to the adequacy of the BLM's gas measurement rules are also significant because they formed one of the bases for the GAO's inclusion of the BLM's oil and gas program on the GAO's High Risk List in 2011 (Report to Congressional Committees, *High Risk Series, An Update*, GAO-11-278). Specifically, the GAO concluded in 2011 "that Interior's verification of the volume of... gas produced from federal leases—on which royalties are due the federal government—does not provide reasonable assurance that operators are accurately measuring and reporting these volumes." (GAO-11-278, p.15.) Because the GAO's recommendations have not yet been fully implemented, the onshore oil and gas program has remained on the High Risk List in subsequent updates in 2013 (Report to Congressional Committees, *High Risk Series, An Update*, GAO-13-283) and 2015 (Report to Congressional Committees, *High Risk Series, An Update*, GAO-15-290).

Proposed Regulations

This proposed rule would replace Order 5, which was published in the *Federal Register* on March 27, 1989 (54 FR 8100), with new regulations at 43 CFR subpart 3175. The proposed rule would establish minimum standards for accurate measurement and proper reporting of gas produced from Federal and Indian (except Osage Tribe) leases, unit PAs, and CAs. It would include requirements for the hardware, software, and procedures related to approved metering equipment, overall measurement performance standards, reporting and record keeping, and variance requests. It also would expand the list of acts of noncompliance found in the current Order 5 that would result in an immediate assessment. Finally, the proposed rule provides a process for the BLM to consider and approve other methods of gas measurement and other methods of determining gas volumes that can be shown to meet the rules' performance standards applicable to such activities. The following table (Table 1 – *Proposed Rule, Gas Measurement, 43 CFR subpart 3175, Side-by-Side*) presents a summary of the existing requirements and proposed changes, and the potential significance of the proposed changes.

Table 1A: Proposed Rule, Gas Measurement, 43 CFR subpart 3175 (Side-by-Side)
(*Note: Appendix A contains a detailed explanation of the cost and benefit estimates presented in Tables 1A, 1B, and 1C. Tables 1B and 1C distribute the aggregate costs in Table 1A across the proposed rule's flow categories for annual and one-time costs, respectively. The row numbers in Tables 1B and 1C correspond to the row numbers in Table 1A.*)

Requirement of Order 5	Requirement of Proposed Rule	Significance of the Change & Overview of Costs/Benefits
1. The current Order has only one requirement pertaining to gas heating value -- that it must be determined once per year.	For high-volume and very-high-volume Facility Measurement Points (FMPs), gas sampling frequency would initially be set to once every 3 months and once every month, respectively. The BLM could adjust the frequency in order to achieve new heating value uncertainty standards. The new sampling frequency would be based on the "BLM Gas Variability Study – Final Report, May 21, 2010" as recommended	The proposed rule change would increase the gas sampling frequency in order to increase the accuracy of heating value determination which is used for royalty calculation. For FMPs that experience a high degree of variability, the proposed change may require the installation of composite samplers or on-line gas chromatographs if the required accuracy cannot be met by spot sampling. **Estimated annual**

Requirement of Order 5	Requirement of Proposed Rule	Significance of the Change & Overview of Costs/Benefits
	by the Subcommittee	**cost: + $14.95 million; one-time cost: $3.69 million** (these one-time costs and the other costs below will be spread over a one to three year phase-in period).
2. The current Order has no requirements for how gas samples are taken, how they are analyzed, or how heating value must be reported.	The proposed rule would increase the accuracy of the measurement of heating values and relative density by establishing requirements for sample probe design and location, for sampling procedures, and for gas chromatographs that are used to determine the heating value of gas samples. All gas analyses would be submitted to the BLM.	The rule could result in the relocation or modification of sample probes at approximately 40,000 FMPs. Requirements of portable gas chromatographs and sample cylinder sealing could affect 30,000 FMPs. Required heat tracing could affect 50,000 FMPs. Extended analysis could affect 4,000 FMPs. The requirement to submit all gas analyses to the BLM would require the development of an on-line database to facilitate electronic submission and analysis of data. **Estimated annual cost: +$29.31 million; One-time retrofit cost: $8.81 million.**
3. The current Order has no immediate assessments.	This proposed rule would impose immediate assessments for several specific violations.	The rule would include a number of categories of violations where immediate assessments could be imposed. In the short-term this may increase the FMP administrator's training, monitoring, and planning costs; however we do not anticipate these increased costs to be significant.
4. Neither the current Order nor the statewide NTLs for electronic flow computers (EFC) require that transducers and flow computers used in conjunction with electronic gas measurement systems (EGM) be type-tested.	The proposed rule would implement a requirement for type-testing transducers and flow computers for EGM systems used at FMPs, as well as a review process and a method for approval and tracking.	It is estimated that there are at least 100 different makes, models, and ranges of transducers. In addition, there are at least 100 different makes and models of flow computers and software versions currently used at FMPs. Under this rule, transducers used at high-or very-high-volume FMPs and flow computers/software versions used at all FMPs would be type-tested by an independent laboratory within the timeframes identified in the proposed rule. **Estimated annual cost is**

Requirement of Order 5	Requirement of Proposed Rule	Significance of the Change & Overview of Costs/Benefits
		negligible; estimated one-time cost: $0.99 million.
5. The current Order requires quarterly calibrations for all meters.	The proposed rule would increase the calibration frequency to monthly for those FMPs measuring more than 1,000 Mcf per day. Calibration frequency would be reduced for meters measuring 100 Mcf per day or less.	Although increased calibration costs would be incurred for the estimated 1,000 FMPs measuring more than 1,000 Mcf per day, cost savings due to less frequent calibrations would be realized for approximately 50,000 FMPs measuring 100 Mcf per day or less, resulting in an overall reduction in calibration costs. **Estimated annual benefit to operators: $8.78 million.**
6. The current statewide NTLs for EFCs established an uncertainty limit of ±3 percent for meters measuring more than 100 Mcf per day.	The proposed rule maintains the current uncertainty requirement for FMPs measuring between 100 Mcf per day and 1,000 Mcf per day, but requires uncertainty to be reduced to a maximum of ±2 percent for FMPs measuring more than 1,000 Mcf per day.	For the estimated 1,000 FMPs measuring more than 1,000 Mcf per day, the more restrictive uncertainty requirement in the proposed rule could require the replacement of transducers or other modifications of the metering system. **Estimated one time retrofit cost: $0.1 million.**
7. The current Order grants automatic approval of chart recorders for all meters.	The proposed rule would disallow chart recorders on FMPs measuring 100 Mcf/day or more because chart recorders are likely not sufficiently accurate to meet the uncertainty requirements.	It is estimated that this would require the replacement of approximately 2,000 chart recorders currently installed at FMPs measuring more than 100 Mcf/day, with EGM systems. **Estimated one time retrofit cost: + $5.2 million.**
8. The current Order requires semi-annual inspection of orifice plates and has no inspection requirements for meter tubes.	The proposed rule would increase the initial orifice plate inspection frequency for all new FMPs and the routine orifice plate inspection frequency for FMPs measuring 100 Mcf per day or more. It would institute a new periodic meter-tube inspection requirement.	The increased inspection frequency for new FMPs would apply to all of the approximately 3000 wells drilled per year. For existing wells, the increased routine inspection frequency for orifice plates would apply to approximately 15,000 FMPs; however, because these would be performed in conjunction with calibrations, the cost is not expected to be significant. Approximately 25,000 FMPs would be subject to the new meter tube inspection requirement. **Estimated annual cost: + $6.25 million**

Requirement of Order 5	Requirement of Proposed Rule	Significance of the Change & Overview of Costs/Benefits
9. The current Order requires that the meter tube and thermometer well comply with American Gas Association Committee Report Number 3 (1985). Temperature measurement is only required for meters flowing more than 200 Mcf per day.	The proposed rule would enforce the meter-tube length and tube-bundle requirements of American Petroleum Institute (API MPMS) 14.3.2 (2000) and would implement new requirements for the placement of thermometer wells in the same ambient temperature as the primary device (e.g., inside the same meter house). In addition, temperature measurement would be required for all FMPs not classified as marginal.	The API standard proposed for adoption by this proposed rule requires longer meter tubes in some cases and also has more strict requirements for tube-bundle design. This could require retrofitting the meter tubes at approximately 3,000 FMPs. Thermometer wells may have to be installed or moved on 3,000 FMPs. **Estimated one time retrofit costs: +$9.5 million.**
10. The current Order has no requirements for how heating value (Btu per scf) is to be reported for royalty purposes.	The proposed rule would establish the basis for reporting heating value. This would include a requirement to report heating value on a dry basis, unless water vapor is physically measured. The reporting of heating value on a "wet" or saturated basis would be prohibited.	Operators currently report heating value on either a dry or saturated basis depending on the provisions of their sales contract. Reporting on a wet basis can lower royalties by as much as 1.74 percent, depending on the flowing pressure and temperature of the gas. **The requirement to report on a dry basis is estimated to increase royalties by $10.21 million per year.** [4]
11. The current Order does not require certain data to be present on site for mechanical recorders.	The proposed rule would require on-site information posted at mechanical recorder locations similar to the on-site data requirements for EGM system.	Operators would have to post placards at chart recorder locations listing the required information. **The estimated one-time cost to retrofit is $0.27 million.**
12. The current Order does not have requirements for gauge lines connecting the primary device to the secondary device.	The proposed rule would establish requirements for the gauge lines connecting the primary device to the secondary device.	The proposed change may require the retrofitting of gauge lines on 2,000 chart recorders and 3,000 EGM systems. **The estimated one-time cost to retrofit is $0.67 million.**
13. The calibration requirements in the current Order are specific to chart recorders and the EFC NTLs generally adopt calibration procedures identified in API MPMS Chapter 21, Section 1, 1993.	The proposed rule would adopt new meter calibration procedures that are contained in the latest version of API MPMS Chapter 21, Section 1, 2013.	The proposed change would reduce the number of points that need to be verified on a routine basis. It would also allow redundancy verification in lieu of routine verification. **Estimated annual cost: $3.12 million plus a one-time cost of retrofitting of $0.21 million**

[4] The projected increase in royalty is a transfer payment and is not considered a direct cost to operators; therefore, it is not included in the total costs, but accounted for separately.

Requirement of Order 5	Requirement of Proposed Rule	Significance of the Change & Overview of Costs/Benefits
14. The current Order has no requirements for Quantity Transaction Records and Configuration Logs associated with EGM systems, and requires flow rates to be calculated in accordance with the American Gas Association Committee Report Number 3, 1985.	The proposed rule would set standards for volume statements (Quantity Transaction Records) and configuration logs associated with EGM systems, and would adopt the most current industry volume and flow rate equations.	Some operators still use the 1985 flow rate equation. This would require upgrading software to comply with the new requirements in API 14.3.3. **Estimate annual cost: $1.2 million plus one time cost to retrofit: $3.47 million**
15. Revisions to civil assessment and civil penalty provisions of 43 CFR 3163.1 & 3163.2.	The proposed rule would make a number of changes to existing regulations related to remedies for acts of noncompliance and civil penalties. These changes conform these sections to applicable statutory requirements and would update that section to conform it to the approach taken to immediate assessments in new subpart 3175. With respect to civil penalties, the revisions would remove the regulatory caps on such assessments.	The changes contemplated by the proposed rule would not change the circumstances where a civil assessments or penalties might be sought, and therefore we do not anticipate these changes would result in any increased costs.
	Total increase in annual operational costs: **Total one-time cost to retrofit:** ***Total estimated increase in royalty payments:***	**$46.05 million** **$32.91 million** ***$10.2 million***[5]

Table 1B – Aggregate Annual Costs by Flow Category for All FMP
(all costs are in $millions, except as noted; *see note above*)

Side-by-side Item From Table 1	Flow Category				Total
	Marginal	Low	High	Very High	
1. Increased Gas Sampling Frequency	**0**	**3.17**	**10.7**	**1.08**	**14.95**
2. Sampling requirements	**2.66**	**9.36**	**15.49**	**1.8**	**29.31**
Probe Design & Placement	0	0	0	0	
Heat Tracing	0.15	0.22	0.1	0.01	
Cleaning and Sealing Sample Cylinders	1.08	3.17	6.12	0.59	
Components to Analyze	0	0	1.22	0.12	
Gas Chromatograph verification	1.19	3.52	6.78	0.65	

[5] The projected increase in royalty is a transfer payment and is not considered a direct cost to operators; therefore, it is not included in the total costs, but accounted for separately.

Side-by-side Item From Table 1	Flow Category				Total
	Marginal	Low	High	Very High	
Entry into GARVS	0.24	2.45	1.27	0.43	
3. Immediate Assessments	N/A	N/A	N/A	N/A	
4. Type Testing Tranducers & Flow Computers	**0**	**0**	**0**	**0**	
5. Calibration frequency	**-4.93**	**-4.42**	**0**	**0.57**	**-8.78**
6. Uncertainty Requirements	**0**	**0**	**0**	**0**	
7. Chart Recorder Replacement	**0**	**0**	**0**	**0**	
8. Orifice Plate and Meter Tube Inspections	**-1.04**	**1.05**	**4.63**	**1.61**	**6.25**
Orifice Plate Inspections	-1.04	0.37	1.92	0.55	
Meter Tube Inspections	0	0.68	2.71	1.06	
9. Meter Tube and Thermometer Well Requirements	**0**	**0**	**0**	**0**	
Minimum Meter Tube Lengths	0	0	0	0	
Elimination of 7-tube Bundles	0	0	0	0	
Thermometer well Placement Requirements	0	0	0	0	
Continuous Temperature Recording	0	0	0	0	
10. Reporting Dry heating Value Requirement[6]	***0.21***	***1.98***	***5.29***	***2.71***	***10.19***
11. On-site Data for Mechanical Recorders	**0**	**0**	**0**	**0**	
12. Manifolds and Gauge Line Requirements	**0**	**0**	**0**	**0**	
13. New EGM requirements	**0.41**	**1.21**	**1.27**	**0.23**	**3.12**
Temperature Transducer Verification	0	0	0	0	
Working Pressure Verification	0.28	0.83	0.87	0.16	
Recertification of Test Equipment	0.13	0.38	0.4	0.07	
14. EGM requirements for Logs and Calculations	**0.38**	**0.55**	**0.25**	**0.02**	**1.2**
New Gas Expansion Factor	0	0	0	0	
New Audit Trail Requirements	0	0	0	0	
Reporting Original Data	0.38	0.55	0.25	0.02	

[6] The projected increase in royalty is a transfer payment and is not considered a direct cost to operators; therefore, it is not included in the total costs, but accounted for separately.

Side-by-side Item From Table 1	Flow Category				Total
	Marginal	Low	High	Very High	
15. **Revisions to Civil Penalty Assessments**	N/A	N/A	N/A	N/A	
Total ($millions)	**-2.52**	**10.92**	**32.34**	**5.31**	**46.05**
Total per FMP ($)	**-118**	**344**	**2,221**	**5,946**	**670**
Estimated Increase in Royalty Payments	***0.21***	***1.98***	***5.29***	***2.71***	***10.19***[7]

Table 1C – Aggregate One-time Costs by Flow Category for All FMPs
(all costs are in $millions, except as noted; *see note above*)

Side-by-side Item From Table 1	Flow Category				Total
	Marginal	Low	High	Very High	
1. Increased Gas Sampling Frequency	**0**	**0**	**2.98**	**0.71**	**3.69**
2. Sampling requirements	**0**	**5.92**	**2.72**	**0.17**	**8.81**
Probe Design & Placement	0	5.92	2.72	0.17	
Heat Tracing	0	0	0	0	
Cleaning and Sealing Sample Cylinders	0	0	0	0	
Components to Analyze	0	0	0	0	
Gas Chromatograph verification	0	0	0	0	
Entry into GARVS	0	0	0	0	
3. Immediate Assessments	N/A	N/A	N/A	N/A	
4. Type testing	**0.31**	**0.46**	**0.21**	**0.01**	**0.99**
5. Calibration frequency	**0**	**0**	**0**	**0**	
6. Uncertainty Requirements	**0**	**0**	**0**	**0.10**	**0.1**
7. Chart Recorder Replacement	**0**	**0**	**5.20**	**0**	**5.20**
8. Orifice Plate and Meter Tube Inspections	**0**	**0**	**0**	**0**	
Orifice Plate Inspections	0	0	0	0	
Meter Tube Inspections	0	0	0	0	
9. Meter Tube and Thermometer Well Requirements	**0**	**6.44**	**2.93**	**0.13**	**9.50**
Minimum Meter Tube Lengths	0	1.85	0.84	0.05	

[7] The projected increase in royalty is a transfer payment and is not considered a direct cost to operators; therefore, it is not included in the total costs, but accounted for separately.

Side-by-side Item From Table 1	Flow Category				Total
	Marginal	Low	High	Very High	
Elimination of 7-tube Bundles	0	0.59	0.27	0	
Thermometer well Placement Requirements	0	2.15	0.98	0.06	
Continuous Temperature Recording	0	1.85	0.84	0.02	
10. Reporting Dry heating Value Requirement[8]	***0***	***0***	***0***	***0***	
11. On-site Data for Mechanical Recorders	**0.11**	**0.16**	**0**	**0**	**0.27**
12. Manifolds and Gauge Line Requirements	**0**	**0.21**	**0.43**	**0.03**	**0.67**
13. New EGM requirements	**0**	**0.14**	**0.07**	**0.004**	**0.21**
Temperature Transducer Verification	0	0.14	0.07	0.004	
Working Pressure Verification	0	0	0	0	
Recertification of Test Equipment	0	0	0	0	
14. EGM requirements for Logs and Calculations	**1.05**	**1.56**	**0.81**	**0.05**	**3.47**
New Gas Expansion Factor	0.75	1.11	0.58	0.04	
New Audit Trail Requirements	0.30	0.45	0.23	0.01	
Reporting Original Data	0	0	0	0	
15. **Revisions to Civil Penalty Assessments**	N/A	N/A	N/A	N/A	
Total ($millions)	**1.47**	**14.89**	**15.35**	**1.20**	**32.91**
Total per FMP ($)	**68**	**469**	**1054**	**1348**	**479**

Alternatives Considered

During the drafting of this rule, a number of alternatives were considered before adopting the provisions in the proposed rule.

Remote Data Acquisition (RDA)

One alternative that was considered was to require raw data generated at the meter to be provided directly to the BLM in real time. This would allow the BLM to independently calculate all gas volumes and compare those volumes with reported values. This alternative was rejected for several reasons based on the results of a pilot project carried out between 2002 and 2009 by the BLM (Remote Data Acquisition and Well Production - RDAWP) to test the viability of just such a system. After eight years and $2 million expended, some limited success was achieved on one lease in Colorado. However, the pilot project revealed significant issues that would make it virtually impossible to implement such systems on a broader scale.

[8] The projected increase in royalty is a transfer payment and is not considered a direct cost to operators; therefore, it is not included in the total costs, but accounted for separately.

These issues are summarized below:

- To be effective, all meters on a lease, unit PA, or CA must be tied into the system. Many leases include mechanical meters and low-end electronic flow computers that do not have communications capability. To require that all meters be capable of RDA would involve a great deal of expense to operators and purchasers (see analysis below).
- The pilot project included only one brand of flow computer which vastly simplified the project. In reality, there are dozens of manufacturers of flow computers and components, each with their own way of generating and storing data. To implement an RDA project on a large scale would increase the complexity and cost of implementation significantly.
- An RDA system would dramatically increase the workload for BLM inspection personnel because legitimate data edits would not be reflected in the raw data. This would result in large amounts of time spent responding to apparent errors that may not exist.
- In lieu of an RDA system, the BLM believes that it can achieve an essentially equivalent level of production accountability utilizing a risk-based approach to production audits and a number of software tools to facilitate the verification process.

Implementing an RDA system would result in significant costs to operators and the BLM, including:

- All mechanical recorders would have to be replaced with electronic gas measurement systems with network/communication capability. We estimate that 15 percent of the 68,000 existing meters are mechanical recorders. Assuming an average cost of $5,000 to upgrade to a suitable EGM system, this requirement would cost $51 million.
- Approximately 50 percent of the meters used for royalty measurement are owned by purchasers (such as pipelines) over whom the BLM has no direct regulatory authority under the mineral leasing statutes with respect to meter standards. For those purchasers unwilling to participate in an RDA system (assume half of them for the purpose of this analysis) operators would have to purchase their own meters. For those purchasers who are unwilling to participate in a RDA system, we estimate that half of them would not allow an EGM system to be tied into the existing orifice plate assembly, requiring the operator to purchase and install both an orifice metering assembly and an EGM system. These costs are summarized as follows:
    - EGM system only: 68,000 meters x 50% x 25% x $5,000 = $42.5 million
    - Entire meter: 68,000 meters x 50% x 25% x $8,000 = $68 million
- We estimate the cost to the BLM of developing an RDA system that would accept the meter data and provide data to the BLM to be at least $10 million. This estimate is based on the cost of the pilot study extrapolated out to encompass all Federal and Indian leases.
- For leases producing marginal volumes, estimated to be 31 percent of all leases (see Table 9), the additional cost of replacing mechanical recorders with EGM systems, or purchasing entirely new meters if the purchaser would not participate in an RDA system, could result in the premature abandonment of these properties. This would result in a loss of royalty of up to $11.5 million per year.
- To investigate and process the high number of discrepancies identified by the RDA system would require hiring approximate 50 new Production Accounting Technicians. At a cost of $57,000 per year (salary and benefits), this would require an additional $3 million per year in personnel costs for the BLM.

These conclusions are supported by a 2013 study by the Office of Natural Resources Revenue, which commissioned, at the direction of the Office of Management and Budget, a study[9] to assess the feasibility of an

[9] "Feasibility of Automated Production Metering Systems in Sending Electronic Data to Onshore Facilities for Analysis", Southwest Research Institute, July 2014 (Project No. 18.17965.01.176)

automated well head metering system. This study came to similar conclusions – that an automated data acquisition is not feasible based on the cost and complexity of implementing such a system.

In sum, we estimate that implementation of an RDA system would cost the BLM and industry in excess of $172 million and would increase operating costs by $3 million per year. We also anticipate that such a system would cause the government to lose $11.5 million per year in royalty payments from the premature abandonment of marginal wells as a result of such a requirement. While it is possible that some additional royalty would be collected using an RDA system that would offset some of this lost revenue, we do not have enough information to quantify the amount. Based on the foregoing, we rejected the RDA system alternative.

Flow-Rate Categories

One of the alternatives considered was to limit the number of flow-rate categories to only “low volume” and “high volume,” rather than the four categories that are being proposed (“marginal,” “low,” “high,” and “very high”). The purpose of the categories is to balance the need to ensure more accurate measurement for higher-volume meters where the risk that the Federal Government or Indian tribes would under-collect or over-collect royalties, a situation known as “royalty risk,” is greater, with the need to ensure that operating costs for lower volume meters which present less royalty risk are reasonable. With only two categories, it would have been much more difficult to achieve this balance. If the threshold between “low” and “high” volume was too low, it would result in higher operating costs for lower volume meters; whereas, if the threshold was too high, it would result in less accurate measurement for higher-volume meters with significant royalty risk.

The cost of implementing a “two-category” system depends entirely on the threshold chosen for “low-volume” and “high-volume” FMPs. However, a two-category approach would probably increase costs for operators overall. For example, if the threshold was chosen to be 100 Mcf per day, all FMPs flowing at more than this threshold (“high volume”) would be held to the proposed standards of a “very-high-volume” FMP to ensure royalty risk (under or over payment) was minimized. Likewise, all FMPs flowing at less than 100 Mcf per day would be held to the proposed standards of a “low-volume” FMP, with no blanket exceptions for FMPs measuring marginal volumes. For these reasons, the use of only two flow-rate categories was rejected.

Sampling frequency

The BLM Gas Variability Study Final Report (May, 2010) concluded that the uncertainty of the average annual heating value for an FMP is a function of the variability of historic heating values and the frequency at which samples are obtained and heating value is determined. For any given meter, the uncertainty of average annual heating value is reduced by increasing the sampling frequency. The study also concluded that the historic variability of heating value is meter-specific and not correlated with any particular attribute of the meter such as location, age, reservoir type, lift type, or richness of the gas. The dynamic sampling frequency (see the preamble discussion under 3175.115(b)) is proposed as a way of ensuring that the uncertainty levels in 3175.30(b) are met and would establish a sampling frequency on a meter-by-meter basis.

An alternative to the dynamic-sampling-frequency approach found in the proposed rule for “high-” and “very-high-” volume FMPs was to adopt a fixed-sampling frequency based on volume. The primary advantage of a fixed sampling frequency is that it would be somewhat easier to implement because the maximum time between sampling would not change for a given category of FMP. By increasing the fixed sampling frequency for higher-volume FMPs, royalty risk could be reduced by requiring more frequent samples. The disadvantage of a fixed sampling frequency is that the sampling frequency would be arbitrary and would not ensure that a specific level of uncertainty would be achieved. For example, an FMP with a highly variable heating value would have a high level of uncertainty even with frequent sampling; whereas, an FMP with very steady heating values would result in a high level of certainty even with a lower sampling frequency. Requiring more frequent sampling in the latter case would be unnecessary for the operator. Dynamic sampling, on the other hand, provides the operator with an economic incentive to exercise good sampling and analysis practice.

Table 2 shows an estimated increase of $14.9 million per year in the cost of implementing the dynamic sampling frequency proposed in subpart 3175, as compared to the annual sampling frequency currently required in Order 5. A one-time cost of $3.7 million would also be required for the installation of composite sampling systems or on-line gas chromatographs in situations where the required levels of uncertainty could not be achieved by spot sampling. Composite sampling systems and on-line gas chromatographs have advantages over spot sampling because they take samples on a nearly continuous basis, thereby eliminating the statistical variability caused by less-frequent spot sampling. Composite samplers accumulate the samples in a sample cylinder which is retrieved and analyzed periodically (typically monthly). On-line gas chromatographs not only sample on a nearly continuous basis (once every 3-5 minutes, typically), they also analyze each sample, eliminating the need to collect the samples in a sample cylinder.

It should be noted that the actual increase in cost to industry associated with this proposed requirement would be substantially lower than the estimated cost shown in Table 2 because many operators already take samples more frequently than once per year as a result of unrelated contractual obligations (e.g., agreements with purchasers). Additionally, because the dynamic-sampling methodology in the proposed rule would encourage operators to use good sampling practices, we believe that implementation of this methodology would significantly reduce heating value variability due to bad sampling practice, which ultimately would result in fewer samples being taken, reducing operator costs over time.

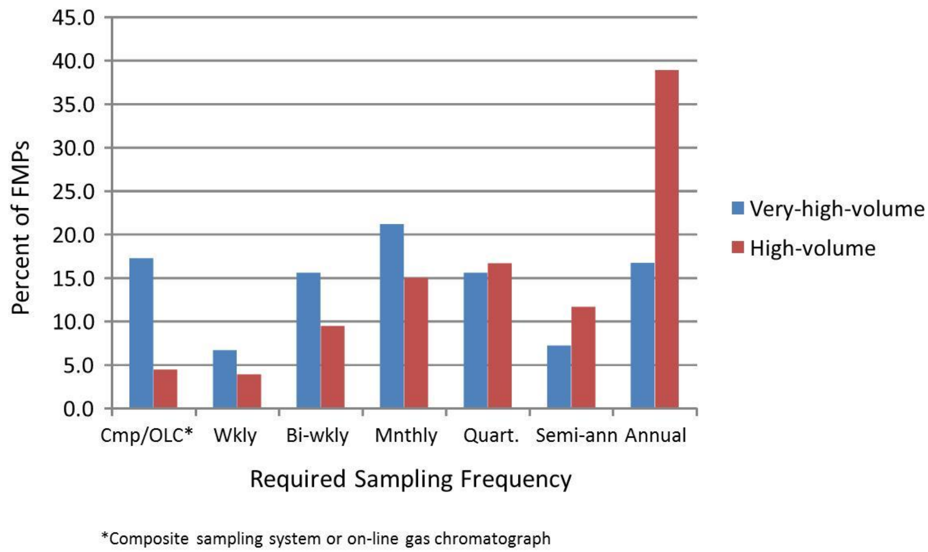
Table 2
Estimated Costs of Implementing Dynamic Sampling Frequency (Preferred Alternative)

	Percent of FMPs				Cost, $millions	
Sample Frequency	Very-high Volume	High-volume	Low-volume	Marginal-volume	Δ annual cost	One-time retrofit
Comp-OLGC*	0.22	0.93			0.80	3.7
Weekly	0.09	0.82			3.15	
Bi-weekly	0.20	1.98			3.74	
Monthly	0.27	3.15			2.58	
Quarterly	0.20	3.50			0.76	
Semi-annually	0.31	10.62	46.2		3.90	
Annually				31.3	0	
Total	1.3	21.1	46.2	31.3	14.93	3.7

*Composite sampling system or on-line gas chromatograph required if weekly sampling was not adequate to achieve the required level of uncertainty.

A total of 0.78 percent of FMPs are very high volume and would have to be sampled at least monthly to achieve an average annual heating value uncertainty of ±1 percent. The FMPs that fell into the annual sampling category as shown in the table would be added to those FMPs in the semi-annual category under the proposed rule because semi-annual sampling would be the minimum sampling frequency allowed. The percentages from Figure 1 were multiplied by the percent of total FMPs in their respective categories (see Table 9) to derive the percent of total FMPs shown in Table 2.

Figure 1
Sampling Frequencies Required to Meet Proposed Uncertainty Limits



Implementing a fixed-sampling frequency for high-volume and very-high-volume FMPs would result in a cost increase of $8.5 million, compared to the current cost of annual sampling required by Onshore Order 5 (see Table 3). This is based on a fixed sampling frequency of monthly for very-high-volume FMPs, quarterly for high-volume FMPs, semi-annually for low-volume FMPs, and annually for marginal-volume FMPs.

Table 3
Estimated Costs of Implementing Fixed Sampling Frequency (Alternative 1)

	Percent of FMPs				Cost, $millions	
Sample Frequency	Very-high Volume	High-volume	Low-volume	Marginal-volume	Δ annual cost	One-time retrofit
Monthly	1.3				0.98	
Quarterly		21.1			4.35	
Semi-annually			46.2		3.17	
Annually				31.3	0	
Total	1.3	21.1	46.2	31.3	8.5	

The costs in the Tables 2 and 3 were derived by multiplying the number of FMPs (assumed to be 68,000) by the percentages shown in Tables 2 and 3. A composite sampling system (comp) was assumed to cost $2,000 to install and would generate 12 samples per year. An on-line gas chromatograph (OLGC) performs both the sampling and analysis automatically and would not generate any external samples. The cost of sampling was assumed to be $100 and the number of samples per year corresponds to the increase in sampling frequency from the annual frequency currently required in Onshore Order 5 (e.g., “monthly” is an increase of 11 samples per year, “bi-monthly” is an increase of five samples per year, etc.).

To implement a fixed sampling frequency for high-volume and very-high-volume FMPs would have required quarterly samples for high-volume FMPs and monthly samples for very-high-volume FMPs. The sampling frequency for low- and marginal-volume FMPs would be the same as those proposed under the dynamic sampling scenario. Annual costs for a fixed sampling frequency would be $8.5 million per year.

While the annual costs of a fixed-sampling methodology are projected to be $10.1 million less than the proposed dynamic-sampling methodology in the proposed rule, the fixed-sampling methodology would not ensure that a set level of heating value uncertainty was met; nor does it incorporate a performance-based standard that would incentivize operators to improve their sampling and analysis practices in the field.

Moreover, it would result in unnecessary costs for some operators that can achieve the uncertainty limits while sampling less frequently. Therefore, the fixed-sampling methodology alternative was rejected.

Heating value uncertainty requirements

The proposed rule sets average annual heating value uncertainty requirements of ±2 percent for high-volume FMPs and ±1 percent for very-high-volume FMPs. Numerous other uncertainty levels were considered during deliberations, including ±3 percent (high volume) and ±2 percent (very high volume), the same levels used for volume uncertainty. Generally, the higher the allowable uncertainty, the lower the cost of compliance and the higher the royalty risk. The BLM decided that the ±3 percent/±2 percent thresholds resulted in too high of a royalty risk and lower uncertainty limits were achievable at relatively little additional cost. Ultimately, the threshold selection was based on the goal of maximizing net benefits by selecting the most cost-effective alternative. For these reasons, we selected the uncertainty thresholds of ±2 percent for high-volume FMPs and ±1 percent for very-high-volume FMPs.

Table 2 (above) summarizes the cost of implementing a dynamic sampling methodology with proposed uncertainty requirements. Table 4 (below) shows the costs of implementing the same methodology with the alternative uncertainty levels.

Table 4: Estimated Costs of Implementing
Dynamic Sampling Frequency – Alternate Uncertainty Limits

	Percent of FMPs				Cost, $millions	
Sample Frequency	Very-high Volume	High-volume	Low-volume	Marginal-volume	Δ annual cost	One-time retrofit
Comp-OLGC*	0.06	0.12			0.14	0.8
Weekly	0.05	0.59			2.24	
Bi-weekly	0.12	0.59			1.22	
Monthly	0.20	3.42			2.73	
Quarterly	0.22	1.53			0.07	
Semi-annually	0.66	14.97	46.2		4.25	
annually				31.3	0	
Total	1.3	21.2	46.2	31.3	10.65	0.8

*Composite sampling system or on-line gas chromatograph required if weekly sampling was not adequate to achieve the required level of uncertainty.

The total annual cost of adopting the less stringent uncertainties is $10.65 million relative to $14.93 million using the proposed uncertainty limits found in the proposed rule. In addition, the initial cost to install composite sampling systems would drop from $3.7 million under the proposed limits to $0.8 million using the less stringent uncertainties. As with the analysis done for the proposed uncertainty limits, the BLM believes the annual costs would drop as the quality control of sampling and analysis improves.

Royalty risk is the uncertainty of measurement (both heating value and flow rate) expressed in royalty dollars instead of percent. Because heating value uncertainty only applies to high- and very-high-volume FMPs, the royalty risk analysis was done only for these two categories. While high-volume FMPs account for 21 percent of total FMPs, the volume measured by high-volume FMPs accounts for 52 percent of the total volume of gas removed or sold from Federal and Indian leases. While very-high-volume FMPs only account for about 1.3 percent of total FMPs, the volume measured by very-high-volume FMPs accounts for 26 percent of total volume. Collectively, high- and very-high-volume FMPs account for 78 percent of all gas removed or sold from Federal and Indian leases.

In Fiscal Year 2014, a total of 2.722 trillion cubic feet of gas were removed or sold from Federal and Indian leases for a total royalty of $1.395 billion (see Table 6). About 1.4 trillion cubic feet (worth $725 million in royalty) were measured by meters that would be classified as high-volume FMPs under the proposed rule. About 0.708 trillion cubic feet (worth $363 million in royalty) were measured by meters that would be classified as very-high-volume FMPs under the proposed rule.

The total royalty risk for high-volume FMPs using the proposed heating value and flow rate uncertainties in this rule (±2 percent and ±3 percent, respectively) would be ±$26.1 million[10]. The total royalty risk for very-high-volume FMPs using the proposed heating value and flow rate uncertainties in this rule (±1 percent and ±2 percent, respectively) would be ±$8.1 million, for a total royalty risk of ±$34.2 million.

The total royalty risk for high-volume FMPs using the alternative heating value uncertainty (±3 percent) would be ±$30.8 million. The total royalty risk for very-high-volume FMPs using the alternative heating value uncertainty (±2 percent) would be ±$10.3 million, for a total royalty risk of ±$41.1 million.

While the alternative heating value uncertainties would reduce annual costs to industry by $4.3 million, it would result in an increase to royalty risk of $6.9 million. Because the royalty risk of implementing the alternative heating value uncertainties was greater than the cost savings from this alternative, the BLM rejected this alternative. It should be noted that amortizing the one-time costs and adding them to annual costs for purposes of this analysis did not affect the conclusion that the preferred alternative maximizes net benefits.[11]

Meter tube and orifice plate inspection frequency

Several alternative meter tube and orifice plate inspection frequencies were considered during the development of the proposed rule. Alternatives included inspections at higher and lower frequencies than what was ultimately decided in the proposed rule. Table 5 summarizes the cost of alternatives analyzed for both orifice plate and meter tube inspection frequencies:

Table 5: Inspection Frequencies

Orifice Plate Inspections

Flow Category	Proposed		Alt 1 – Less Stringent		Alt 2 – More Stringent	
	Frequency (insp/yr)	ΔCost ($million)	Frequency (insp/yr)	ΔCost ($million)	Frequency (insp/yr)	ΔCost ($/million)
Marginal	1	-1.1	1	-1.1	2	0
Low	2	0	2	0	4	3.2
High	4	1.4	3	0.73	6	2.9
Very high	12	0.4	6	0.18	12	0.45
Total		0.7		-0.2		6.55

Detailed Meter Tube Inspections

Flow Category	Proposed		Alt 1 – Less Stringent		Alt 2 – More Stringent	
	Frequency (yr/insp)	Cost ($million)	Frequency (yr/insp)	Cost ($million)	Frequency (yr/insp)	Cost ($/million)
Marginal	0	0	0	0	0	0

[10] Total measurement uncertainty is the root-sum-square of heating value uncertainty and flow rate uncertainty

[11] To support this conclusion, we ran an analysis that turned the one-time cost into an annual equivalent by amortizing the one-time costs over 5 years at a 3% interest rate. For the preferred alternative, the annual cost of a $3.7 million one-time cost, spread over 5 years at a 3% interest rate is $665,000/year. The amortized cost of the $0.8 million one-time cost of the lower uncertainty alternative is $144,000 per year. Adding those amortized costs to the annual costs result in a total cost for the preferred alternative of $15.6 million ($14.93 + $0.665) and the total cost of the alternative of $10.8 million ($10.65 + $0.144). The difference in costs is $4.8 million; however, the difference in royalty risk estimates between the alternatives is $6.9 million which is greater than the additional cost of the preferred alternative. Therefore, we believe the additional cost of the preferred alternative is justified.

Low	0	0	0	0	10	2.8
High	10	1.7	0	0	5	3.3
Very high	5	0.65	10	0.32	2	1.6
Total		2.3		0.32		7.7

Visual Meter Tube Inspections

Flow Category	Proposed		Alt 1 – Less Stringent		Alt 2 – More Stringent	
	Frequency (yr/insp)	Cost ($million)	Frequency (yr/insp)	Cost ($million)	Frequency (yr/insp)	Cost ($/million)
Marginal	0	0	0	0	0	0
Low	5	0.68	10	0.34	3	1.1
High	2	1.0	5	0.42	2	1.0
Very high	1	0.41	2	0.20	1	0.41
Total		2.1		1.0		2.5

Reducing the inspection frequencies below the frequency set forth in the proposed rule would result in some minor cost savings, but would increase royalty risk by increasing the potential for inaccurate measurement. At the same time, increasing the inspection frequencies above the frequency set forth in the proposed rule would result in higher costs with relatively little reduction in the royalty risk relative to the proposed rule. The quantification of royalty risk is difficult to assess because it is unknown how much increased uncertainty results from meter tubes and orifice plates that do not comply with API standards. However, given that Federal onshore and Indian royalties amounted to $1.32 billion in FY14, even a 1 percent error could amount to a $13 million error in royalty annually. Based on field experience, the BLM believes the proposed alternative balances compliance costs and reductions in royalty risk.

Measurement equipment

While the proposed rule addresses only flange-tapped orifice plate meters, the inclusion of other types of meters such as ultrasonic, turbine, and Coriolis meters was also considered. While some of these meters offer higher accuracy than orifice plate meters, they also are more difficult to verify independently and are not widely used for lease-level measurement of gas because of the associated costs. Because the inclusion of other types of meters would add to the complexity of the rule with no significant benefits, these alternatives were not included in the proposed rule. The costs incurred by including these alternative meters could be significant for the BLM and would be due primarily to the incorporation of additional industry standards and training of BLM inspectors and engineers.

Background

Federal and Indian (except Osage Tribe) Oil and Gas Leases

The BLM Oil and Gas Management Program is one of the most important mineral leasing programs in the Federal Government. The latest Public Land Statistics data indicates there were 46,183 Federal oil and gas leases covering 34,592,450 acres in fiscal year (FY) 2014. For FY 2014, there were 94,772 producible and service holes and 101,147 producible and service completions on Federal leases.[12]

For FY 2014, the Office of Natural Resources Revenue (ONRR) reported 148 million bbl of oil, 2.48 trillion cubic feet of natural gas, and 2.9 billion gallons of natural gas liquids were sold from onshore Federal oil and gas leases and generated approximately $3.1 billion in royalties. Nearly half of these revenues are distributed to

[12] U.S. Department of the Interior, Bureau of Land Management, FY 2014 Public Land Statistics data as of October 20, 2014.

the States in which the leases are located. The sales value of the oil and gas sold from public lands was $27 billion. Oil and gas production from Indian leases was nearly 56 million bbl of oil, 240 billion cubic feet of natural gas, and 182 million gallons of natural gas liquids, with a sales value of over $6 billion and generating royalties of over $1 billion that were all distributed to the applicable tribes and individual allottee owners. (Table 6 – *Federal and Indian Oil and Gas Production, Sales Value, and Royalties FY 2014*.)

Table 6: Federal and Indian Oil and Gas Production, Sales Value, and Royalties FY 2014

	Sales Volume	Sales Value	Royalty
Federal Leases			
Oil (bbl)	148,802,549	$13,320,628,635	$1,623,739,874
Gas (Mcf)	2,481,828,141	$11,185,411,281	$1,230,517,935
NGL (gal)	2,900,242,503	$2,663,431,070	$242,936,157
Total		$27,169,470,986	$3,097,193,966
Indian Leases			
Oil (bbl)	55,830,326	$4,893,053,931	$857,273,933
Gas (mcf)	240,775,678	$1,060,252,553	$164,674,607
NGL (gal)	182,333,925	$174,764,850	$21,420,547
Total		$6,128,071,334	$1,043,369,087

Source: U.S. Department of the Interior, ONRR, *Federal Onshore Reported Royalty Revenue – FY 2014,* and *American, Indian Reported Royalty Revenue – FY 2014, (6/30/2015)*

Number of Potentially Affected Entities

For purposes of identifying the number of entities potentially affected by this proposed rule, we relied on several data sources, including the U.S. Census Bureau's 2011 mining industry data. Table 7 – *Oil and Gas Extraction by Employment Size* identifies the number of entities grouped by the number of employees working for each firm. Based on U.S. Census Bureau data, in 2011 there were 6,628 firms directly involved in extraction of oil and gas in the United States.

Table 7
Oil and Gas Extraction by Employment Size

NAICS Code	Description	Data Type[13]	Employment Size		
			Total	<500	500+
21111	Oil and Gas Extraction	Firms	6,628	6,530	98
21111	Oil and Gas Extraction	Establishments	8,095	6,794	1,301
21111	Oil and Gas Extraction	Employment	118,959	47,374	71,585
21111	Oil and Gas Extraction	Annual Payroll ($1,000)	14,484,598	4,630,887	9,853,711

Source: U.S. Census Bureau, Statistics of U.S. Businesses, *Number of Firms, Number of Establishments, Employment, and Annual Payroll by Employment Size of the Enterprise for the United States, All Industries 2011 – (http://www.census.gov/econ/susb/).*

Entities that would be directly affected by the proposed rule would include most, if not all, firms involved in the extraction of oil on Federal and Indian lands. Although this rulemaking would only affect entities involved in the extraction of gas resources on Federal and Indian (except Osage Tribe) lands, there is no practical way to determine exactly which firms would lease and/or operate on Federal or Indian lands in the future. Therefore, the approximately 6,628 firms associated with extraction of domestic oil and gas[14] represent an upper bound estimate of the operators that could potentially be affected by this rulemaking.

[13] Firms are business organizations consisting of one or more domestic establishments in the same state and industry that were specified under common ownership or control. An establishment is a single physical location where business is conducted or where services or industrial operations are performed.
[14] U.S. Census Bureau data does not readily differentiate between the number of firms involved in oil production versus gas production.

Affected Small Entities

The Small Business Administration (SBA) has developed size standards to carry out the purposes of the Small Business Act and those size standards can be found in 13 CFR 121.201. Small entities for mining, including the extraction of crude oil and natural gas, are defined by the SBA as an individual, limited partnership, or small company considered being at "arm's length" from the control of any parent companies, with fewer than 500 employees.

Of the 6,628 domestic firms involved in oil and gas extraction (Table 3), 99 percent or 6,530 had fewer than 500 employees. Based on the available national data, the preponderance of firms involved in producing oil and gas from Federal and Indian lands are small entities as defined by the SBA. As such, it appears a substantial number of small entities would be potentially affected by the proposed rule.

Analysis

Impact Significance

In addition to determining whether a substantial number of small entities are likely to be affected by this rule, the BLM must also determine whether the proposed rule is anticipated to have a significant economic impact on those small entities.

We estimate there would be a one-time transition cost associated with implementing the proposed changes of as much as $33 million, or about $9,000 per entity[15] affected by the proposed rule. These one-time costs would be spread out over a one- to three-year transition period. On an ongoing basis, we estimate the proposed changes would increase the industry's annual net operating costs by about $46 million, or about $13,000 per entity[16] per year. The above per entity cost increases are averages. The actual cost increase for a particular entity will depend on the company's level of activity, including the number of high-volume FMPs. In addition to the increased costs associated with implementing the proposed provisions, we estimate the requirement to report sales volumes on a dry basis would increase Federal royalty payments by $10.2 million per year. All of the proposed provisions would apply to entities regardless of size. However, entities with the greatest activity would likely experience the greatest increase in compliance costs.

The RFA does not define "significant." Significance must be determined on a case-by-case basis. Significance should not be viewed in absolute terms, but be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors.

Recognizing that the SBA definition for a small business is one with fewer than 500 employees and that presents a wide range of possible oil and gas producers, the BLM looked at company data for 26 different small-sized entities that currently hold competitive Federal oil and gas leases. The BLM ascertained the following information from the company's annual 10-K reports to the U.S. Securities and Exchange Commission (SEC) for 2012-2014 (Appendix B - *SEC Small Entity Data*).

From the data in the 10-K reports, the BLM was able to calculate the company's profit margin[17] for the years 2012, 2013 and 2014. We then calculated a profit margin figure for each company when subject to the average annual cost increase associated with this rule. For these 26 small companies, the average annual cost increase

[15] We estimate that 3,706 existing operators would be affected by the proposed changes based on data in Automated Fluid Minerals Support System (AFMSS).
[16] We estimate that 3,706 existing operators would be affected by the proposed changes based on data in AFMSS.
[17] The profit margin was calculated by dividing the net income by the total revenue as reported in the companies' 10-K filings.

of $13,000 per entity resulted in a reduction in the profit margins ranging from 0.0005 percent to 0.5742 percent. For 2014, the average reduction in the profit margin for these 26 small entities was 0.0362 percent.

As discussed above, the $13,000 per entity per year figure is an average cost. Entities with higher activity levels would be subjected to a higher cost than the average. We assume small entities, as defined by SBA, would generally have lower activity levels and thus face a lower annual cost increase than the average. As such, the range of profit margin reduction figures is likely an over estimate.

Based on the available information, we conclude that the proposed rule would not have a significant impact on a substantial number of small entities. Therefore, a final Regulatory Flexibility Analysis is not required, and a Small Entity Compliance Guide is not required.

Direct Economic Impacts

The proposed rule prescribes a number of specific requirements for production measurement, including sampling, measuring and analysis protocol, categories of violations, and reporting requirements. The proposal also establishes specific requirements related to the physical makeup of meter components.

To estimate the economic impacts of the proposed changes, the BLM researched the costs of equipment and the amount of time that would be required to comply with the proposed changes. The BLM research effort included surveying operators, service providers, and manufacturers to estimate the costs of each change. Once the unit cost of each new requirement was determined, the number of FMPs that would be subject to the new requirement was estimated by querying The BLM's Automated Fluid Minerals Support System (AFMSS) for existing gas metering facilities. The AFMSS database consists of all gas meters that may be on a lease, unit PA, or CA. This includes meters used in the determination of Federal or Indian royalty as well as those meters used as check meters, meters required by State agencies, or installed for company purposes such as allocating production to working interest owners. Only those meters used in the determination of Federal or Indian royalty would become FMPs subject to the requirements of the proposed rule. Because the AFMSS database does not currently distinguish meters used in the determination of royalty from other types of meters, the BLM assumed that all the 68,684 gas meters listed in the AFMSS database would become FMPs. The BLM also determined that approximately 3,706 existing operators would be potentially affected by the proposed changes by querying AFMSS by operator.

Because the proposed requirements vary based on average flow rate, it was also necessary to estimate the percentage of FMPs that would be classified as "marginal volume," "low volume," "high volume," and "very-high volume." Costs of compliance would generally increase as the average flow rate increases because the higher the average flow rate, the more restrictive the requirements would be. While the BLM has access to monthly volumes of gas sold or transferred from Federal and Indian leases, unit PAs, and CAs, the FMPs from which these volumes are determined are not currently tracked. In other words, a lease with four wells could have an FMP on each well, or a single FMP to measure the combined production of all four wells. To work around this limitation, the BLM queried the volumes of gas sold or transferred from leases, unit PAs, or CAs with only one well for the month of July 2014. Using this method resulted in a direct correlation between volume reported for each lease, unit PA, or CA, and volume measured by each respective FMP.

Of the 29,302 leases, unit PAs, and CAs reporting gas production for July 2014, 11,190, or 38 percent, have only one well reported. It is assumed, therefore, that one-well leases, unit PAs, and CAs are statistically representative of all leases, unit PAs, and CAs. Once the volume for each FMP was determined, it was divided by 31 days to determine the average flow rate, and then sorted to determine the number of FMPs that fell into each flow-rate category proposed in this rule (marginal, low, high, or very-high), with the following results:

Table 9
Flow Rate Category

Flow Rate Category	Percent of Total
Marginal	31.3
Low	46.2
High	21.2
Very High	1.3

Source: BLM's Automated Fluid Mineral Support System

Based on this analysis, we estimate these requirements would increase the operators' annual expenses by a net amount of approximately $45.5 million (Table 1). In addition, we estimate annual royalty payments would be increased by as much as $10.2 million. There would also be a one-time cost to retrofit existing equipment of about $33 million, which would be spread over one to three years. These increased costs are due to increased sampling, modification, and replacement of equipment, increased staffing and training, and increased inspections. It should be noted that these cost estimates are based on the difference between current requirements and proposed requirements. It is recognized that many operators may already have equipment and practices in place that comply with the proposed requirements to some degree; therefore, the cost estimate is probably significantly higher than the actual cost to the industry. For example, ONRR regulations (30 CFR 1205.152(a)(2)) require operators to measure the Btu content of the gas at least twice per year. Assuming operators currently comply with this requirement, then the additional costs of the sampling frequencies proposed in this rule would be $10.3 million, instead of $15 million based on the current requirements of Order 5.

The projected cost increases discussed above are associated with the operators complying with the proposed rule to ensure accuracy and verifiability of production measurements and to ensure the integrity of the government's royalty collections. To put these added costs in perspective, onshore natural gas production (including NGLs derived from natural gas) from Federal and Indian (except Osage Tribe) leases generates over $1.6 billion in royalties in FY 2014 (Table 6).

The proposed rule would also impose immediate assessments (not to exceed a total of $5,000 per lease, unit PA, or CA per inspection) for specific violations. In the short-term this may increase the operator's training, monitoring, and planning costs. Also, although the amount of the proposed immediate assessment may or may not be relatively significant, the number of violations is anticipated to be relatively small.

The proposed changes would also increase the BLM's workload related to the production measurements. These added expenses would relate to incorporating the new requirements into existing management practices and procedures, and managing sampling increases. In most cases, these increased costs would be relatively minor and would likely be offset by efficiency gains.

The proposed rule would also establish the basis for reporting heating value for royalty calculation purposes. This would include a requirement to report heating value on a dry basis, unless water vapor is physically measured. Operators currently report heating value on either a dry, saturated, or "as delivered" basis, depending on the provisions of their sales contract. Reporting on a wet basis can lower royalties by as much as 1.74 percent, depending on the flowing pressure and temperature of the gas. We estimate the requirement to report on a dry basis would increase royalty payments by up to $10.2 million per year.[18]

[18] The estimated value of $10.2 million was derived by assuming that 50 45 percent of gas is reported as "wet". If this gas was reported as "dry", as proposed in this rule, then the royalty value of that gas would increase by 1.74 percent. Therefore, the total gas royalty ($1.1753 billion) times 5045%, times 1.74 percent, equals $10.2 million.

The BLM developed four categories (marginal-, low-, high-, and very high-volume) of FMPs to ensure that operators of marginal wells were not burdened with additional costs, while operators of higher volume wells achieved set levels of uncertainty and verifiability. The proposal to report “dry” heating value is estimated to cost operators of marginal wells an additional $10 per FMP per year in royalty. However, other proposed requirements, such as the reduction of calibrations and orifice plate inspections for marginal-volume FMPs, would result in a net savings to operators of $118 per FMP per year as compared to current requirements under Order 5 (see Tables 1A and 1B). Therefore, we do not anticipate any reduction in gas production due to this proposed rule.

Conclusion

The Regulatory Flexibility Act requires agencies to analyze the economic impact of proposed and final regulations to determine the extent to which there is anticipated to be a significant economic impact on a substantial number of small entities. Although we anticipate the proposed rule to affect most, if not all, current and future operators on Federal and Indian lands, and most operators are small entities as defined by the SBA, we do not expect the impact to be significant. Based on our analysis presented above, we anticipate the proposed provision to potentially reduce most companies’ annual net income by less than one tenth of one percent. All of the proposed provisions would apply to entities regardless of size. However, entities with the greatest activity would likely experience the greatest increase in compliance costs.

Executive Order 12866, the Unfunded Mandates Reform Act, and the Small Business and Regulatory Flexibility Act require agencies to assess, where practical, the anticipated costs and benefits of proposed regulatory actions to determine if it is a significant regulatory action. We estimate the annual effect on the economy of the regulatory changes would be less than $100 million and would not adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local or tribal governments or communities. This rule would not create inconsistencies or otherwise interfere with an action taken or planned by another agency. This rule does not change the relationships of the oil and gas programs with other agencies' actions. These relationships are included in agreements and memoranda of understanding that would not change with this rule. In addition, this rule does not materially affect the budgetary impact of entitlements, grants, loan programs, or the rights and obligations of their recipients.

We make this determination based on our analysis discussed above; we estimate these requirements would increase operator annual expenses by a net amount of approximately $46 million and would require one-time retrofit costs to existing equipment of about $33 million, which costs would be spread over one to three years. In addition, we estimate the requirement to report on a dry basis would increase royalty payments by as much as $10.2 million per year. We do not anticipate any associated economic impacts, such as a reduced output, due to the higher royalty payments.

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Appendix A – Calculation of Costs for Tables 1A-1C

This Appendix explains how the costs estimates in Tables 1A, 1B, and 1C were developed. These calculations utilize a common set of assumptions about the number of facilities potentially affected by the proposed rule, the share of production from those facilities, their average flow rate, and the total number of gas samples taken at them. These assumptions are shown in Table A.1, below. An explanation of the way these values were derived can be found in the "Direct Economic Impacts" section of the Economic and Threshold Analysis.

Table A.1. Global Assumptions Used in the Economic Impact Analysis

FMP Category	Number	Percent of Total	Percent of Total by Volume	Average Flow (Mcf/day)	Number of gas samples per year
Marginal-volume	21,498	31.3	2.1	7	21,498
Low-volume	31,732	46.2	19.4	44	63,464
High-volume	14,561	21.2	51.9	259	122,441
Very high-volume	893	1.3	26.6	2142	11,796
Total	**68,684**	**100.0**	**100.0**		**219,199**

At the outset it should be noted that for each of the cost summary tables below, the "Cost per FMP" is the total cost of the requirement for each flow category divided by the total number of FMPs in that flow category (using the "Number" of facilities reported in Table A.1). The average "Cost per FMP" is the total cost of the requirement divided by the total number of FMPs (68,684).

1. Increased Gas Sampling Frequency

Order 5 requires that: "[t]he BTU content shall be determined at least annually, unless otherwise required." Proposed rule section 3175.115(a) and (b) would increase the sampling frequency for low-, high-, and very high-volume FMPs. There is no change proposed for marginal-volume FMPs. The sampling frequency for low-volume FMPs would double under the proposed rule to once every 6 months, as opposed to annually. For high- and very-high volume FMPs, the sampling frequency would vary from weekly to semi-annually based on the historic variability of the heating value of the gas measured at a particular FMP. The higher the variability, the more frequently samples would have to be taken. Additionally, for those high- and very high-volume FMPs where the heating value uncertainties proposed in 3175.30(b) could not be met by spot sampling, the operator would be required to install a composite sampling system or an on-line gas chromatograph.

The estimated sampling frequency is shown in Table 4 above. Similarly, a detailed discussion of the economic impacts of this proposal is given in the discussion of sampling frequency alternatives above. Table A.2 distributes those costs among FMPs by flow category.

Table A.2

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0	0	0
Low-volume	3.17	0	100	0
High-volume	10.7	2.98	734	205
Very high-volume	1.08	0.71	1,209	795
Total	**14.95**	**3.69**		
Average			**218**	**54**

2. Sampling requirements

Order 5 has no requirements for how or where samples are taken or how they are analyzed. The proposed rule would establish requirements for:

- Sample probe design and placement
- The use of heat tracing in sampling systems
- A method to ensure sample cylinders have been cleaned to API and GPA standards
- The components in a gas sample that must be analyzed
- Verification of gas chromatographs
- The entry of all gas analyses into a BLM database

Sample probe design and placement

The proposed rule would require operators to locate the sample probe no further than 2 times the minimum required downstream meter tube length from the primary element (3175.112(b)(1)) and in the same ambient temperature condition as the primary element (3175.112(b)(2)). This requirement would not apply to marginal-volume FMPs.

The BLM estimates that the sample probes in about 90% of all FMPs to which this rule applies (low-, high-, and very high-volume FMPs), would have to be relocated to comply. Low-, high-, and very high-volume FMPs make up about 68.7% of all FMPs (see Table A.1). Assuming that 90% of those would be affected by the new requirement, 61% of all FMPs (approximately 42,000 FMPs) would require retrofits. The BLM estimates that relocating the sample probe would cost about $200.[19] The total cost of this retrofit is $8.4 million ($200 x 42,000 FMPs).

Order 5 does not require each meter to have a sampling probe. The proposed rule would require operators to install such a probe. It should be noted, however, that most operators have already installed them on their facilities. The BLM estimates that operators of 15% of all FMPs (10,300 meters) would be required to purchase a sampling probe in order to comply with this new requirement. A sampling probe costs approximately $40 for a total additional cost of $412,000 ($40 x 10,300 FMPs).

In some existing meter installations, the operator may be able to comply with the proposed requirement by switching the thermometer well and the sampling port at a much lower cost. However, for the purpose of this analysis, it was assumed a complete retrofit would be required. The total cost of this requirement was distributed to each flow rate category in proportion to the number of FMPs in each category (see Table A.1 above). A summary of costs is given in Table A.3:

Table A.3

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0	0	0
Low-volume	0	5.92	0	187
High-volume	0	2.72	0	187

[19] The proposed work would require the FMP to be shut in; a hole would be drilled downstream of the orifice plate in the appropriate location, a threadolet would be welded into the hole, and a sample probe would be installed in the threadolet. A 1” threadolet costs about $95 and the work required to install the threadolet is estimated to take 1 hour at $80 per hour. In addition, the one-hour loss of production required for this one-time retrofit would result in a $7 loss of revenue in an average low-volume FMP, a $43 loss of revenue in an average high-volume FMP, and a $360 loss of revenue in an average very high-volume FMP. The weighted average one-time loss of revenue for all affected FMPs is $25 per FMP.

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Very high-volume	0	0.17	0	187
Total	**0**	**8.81**		
Average			**0**	**187**

Heat tracing

The proposed rule (3175.111(b)) would require the use of heat tracing on all components of the sampling system that are exposed to ambient temperatures less than 30 degrees above the hydrocarbon dew point of the gas. Based on field observations, the BLM estimates that this would require heat tracing on 70% of all FMPs, or 48,000 FMPs. The BLM assumed the remaining 30% of FMPs would not need heat tracing because the operator determined that the hydrocarbon dew point was significantly less than the flowing temperature of the gas or the ambient temperature was greater than 30 degrees above the flowing temperature of the gas at the time the sample would be taken.

The BLM also assumes that a heat tracing system would be carried by the person taking the sample and that one heat tracing system would be used on 10 FMPs. Through discussions with some operators, the BLM estimates that the cost of a heat tracing systems is about $100. The total of this requirement is $481,000 (0.7 x 68,684 x $100/10). Because heat tracing systems are easily damaged, the BLM assumed this is an annual cost and not a one-time cost. The total cost of this requirement was distributed to each flow rate category in proportion to the number of FMPs in each category shown in Table A.1. These costs are summarized in Table A.4.

Table A.4

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0.15	0	7	0
Low-volume	0.22	0	7	0
High-volume	0.10	0	7	0
Very high-volume	0.01	0	7	0
Total	**0.48**	**0**		
Average			**7**	**0**

Cleaning and sealing sample cylinders

The proposed rule would require operators to clean the sample cylinder in accordance with GPA standards before every sample is taken (3175.113(c)(3)) and is also proposing to require a method of sealing the cylinder to ensure that it has been cleaned (3175.113(c)(4)). Based on discussions with operators, the BLM estimates that the cost of cleaning and sealing a sample cylinder is $100, and would be required prior to all samples taken using a sample cylinder. Based on field observations, the BLM estimates that 50 percent of samples would be taken using a sample cylinder; the other 50 percent would be taken with a portable gas chromatograph, in which case sample cylinders are not used. The total cost reported below is based on the estimated number of samples for each flow rate category given in Table A.1 above. Following the Table A.5 is a sample calculation that explains how these values were derived.

Table A.5

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	1.08	0	50	0

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Low-volume	3.17	0	100	0
High-volume	6.12	0	424	0
Very high-volume	0.59	0	661	0
Total	**10.96**	**0**		
Average			**160**	**0**

For example, the total cost of this requirement on marginal-volume FMPs is the number of gas samples for marginal-volume FMPs from Table A.1 (21,498), times the percent of FMPs that use sample cylinders instead of portable gas chromatographs (50 percent), times the cost of cleaning and sealing per cylinder ($100). Multiplying these together (21,498 x 0.50 x $100) give a total cost of $1.075 million. The cost per FMP is the total cost of this requirement for marginal-volume FMPs divided by the total number of marginal-volume FMPs ($1.08 million divided by 21,498 FMPs is $50/FMP).

Components to analyze

The proposed rule (3175.119(b)) would require an extended analysis of hydrocarbon components (through nonane) if the analysis of hexane-plus from a typical analysis was greater than 0.25 mole percent. Marginal- and low-volume FMPs would be exempt from this requirement. Based on its extensive experience reviewing gas analyses, the BLM estimates that 5% of gas samples from high- and very high-volume FMPs will require an extended analysis under the proposed rule. The additional cost of doing the extended analysis was estimated to be $200, which was determined by talking to gas analysis laboratories. The total cost incurred by this requirement is summarized in Table A.6.[20]

Table A.6

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0	0	0
Low-volume	0	0	0	0
High-volume	1.22	0	84	0
Very high-volume	0.12	0	134	0
Total	**1.34**	**0**		
Average			**160**	**0**

Gas chromatograph requirements

The proposed rule would require portable gas chromatographs to be verified within 24 hours (3175.118(c)(1)) before taking a gas sample and laboratory chromatographs to be verified not less than once every 7 days (3175.118(c)(2)). This requirement would apply to all flow rate categories.

Based on field experience, the BLM assumed that portable gas chromatographs would be used on 50 percent of all FMPs and that 6 FMPs could be analyzed within the 24-hour time period proposed in subpart 3175. From discussions with operators, the BLM also assumed that the cost to verify a gas chromatograph is $200. The total cost for implementing this requirement on portable gas chromatographs is $3.353 million (219,199 samples x

[20] For example, the cost of performing an extended analysis on high-volume FMPs is the number of samples that would be required for high-volume FMPs from Table A.1 (122,441), times the percent of samples that contain more than 0.25 mole percent of hexane+ (5%), times the cost to perform an extended analysis ($200), for a total cost of $1.22 million (122,441 x 0.05 x $200). The "Cost per FMP" is the total cost ($1.22 million) divided by the total number of high-volume FMPs (14,561), which is $84 per FMP.

50% x $200/(6 samples per verification)). For laboratory gas chromatographs, the BLM assumed that they would be used on the 50% of all FMPs that did not use portable gas chromatographs and that 80 samples could be analyzed within the 7-day timeframe proposed in subpart 3175. The total cost for implementing this requirement for laboratory gas chromatographs is $273,999 (219,199 samples x 50% x $200/(80 samples per verification)).

The proposed rule (3175.113(d)(2)) would also require that the filter at the inlet to portable gas chromatographs be cleaned or replaced prior to taking each sample. The BLM assumed that the cost to clean or replace a filter is $75 based on discussions with operators. The total cost of implementing this requirement is $8,219,963 (219,199 samples x 50% x $75).

Table A.7 summarizes the costs of the proposed requirements for the verification of portable and laboratory gas chromatographs (a sample calculation follows the table).

Table A.7

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	1.19	0	55	0
Low-volume	3.52	0	111	0
High-volume	6.78	0	466	0
Very high-volume	0.65	0	728	0
Total	**12.14**	**0**		
Average			**176**	**0**

An example calculation for Low-volume FMPs is given below:

- *Cost to verify portable gas chromatographs*: 63,464 samples x 50% x $200 ÷ 6 samples/verification = $1.058 million
- *Cost to verify laboratory gas chromatographs*: 63,474 samples x 50% x $200 ÷ 80 samples /verification = $79,000
- *Cost to replace filters on portable gas chromatographs*: 63,474 samples x 50% x $75 = $2.388 million
- **Total Cost: $1.058 million + $79,000 + $2.388 million = $3.52 million**

Entry of gas analysis into BLM database

The proposed rule (3175.120(f)) would require the operator to enter the results of all gas analyses into a BLM database (GARVS). The BLM estimates that it would require $20 in labor cost to enter each gas analysis into GARVS, for a total cost of $4,383,980 (219,199 samples x $20). The BLM recognizes that most operators already have gas analysis information in electronic format and significant time and cost savings would be realized by uploading that data into GARVS instead of key entering it online; however, for purposes of estimating potential impacts of the proposed rule it was assumed all data would be entered on line. The costs were distributed to each flow category in proportion to the number of samples that would be taken for that flow category from Table A.1. Table A.8 summarizes the costs of the proposed requirement:

Table A.8

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0.24	0	11	0
Low-volume	2.45	0	77	0

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
High-volume	1.27	0	87	0
Very high-volume	0.43	0	481	0
Total	**4.39**	**0**		
Average			**64**	**0**

3. Immediate Assessments

The BLM does not estimate that the immediate assessments proposed in this rule would result in any costs to operators, because the BLM presumes compliance for purposes of this economic impact analysis.

4. Type Testing Transducers and Flow Computers

The proposed rule would require that all transducers (3175.43) and flow computers (3175.44) be type tested and approved by the BLM in order to be used at an FMP. All testing would be a one-time cost of every make, model, and range of transducer, and for every make and software version for flow computers. Based on the number of devices currently in the BLM Uncertainty Calculator, the BLM estimates that initially 100 different existing makes, models, and ranges of transducer would be type tested and that each test would cost $5,000. The BLM also assumes that initially 100 different makes of flow computers and software versions would be tested, also at a cost of $5,000 per test. The cost per test was estimated from the cost of laboratory testing of other devices that the BLM has been involved with. This would result in a total cost of $1,000,000 (100 transducers x $5,000 per test plus 100 flow computer software versions x $5,000 per test). The total cost of this requirement was distributed to each flow rate category in proportion to the number of FMPs in each category shown in Table A.1.The total cost is summarized in Table A.9.

Table A.9

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0.31	0	15
Low-volume	0	0.46	0	15
High-volume	0	0.21	0	15
Very high-volume	0	0.01	0	15
Total	**0**	**0.99**		
Average			**0**	**15**

5. Calibration Frequency

Order 5 requires that all meters be calibrated at least quarterly, regardless of average flow rate. Section 3175.92(b) (for mechanical recorders) and 3175.102(b) (for electronic gas measurement systems) of the proposed rule would change the calibration frequency for these systems to the following frequencies based on the flow rate category a given FMP. Those requirements are summarized in the table below:

For Mechanical recorders:

Flow Category	Proposed Calibration Frequency (months)	Change from Order 5 (calibrations per year)
Marginal volume	6	-2
Low volume	3	0

For Electronic gas measurement systems:

Flow Category	Proposed Calibration Frequency (months)	Change from Order 5 (calibrations per year)
Marginal volume	12	-3
Low volume	6	-2
High volume	3	0
Very high volume	1	+8

For this analysis, the BLM assumed that each calibration costs $80.[21] The change in cost for each category was calculated by multiplying the number of FMPs within each category by the change in calibration frequency proposed in the rule, and then multiplying that by $80. Based on field experience, the BLM assumed that 10 percent of all FMPs are mechanical recorders and 90 percent are electronic gas measurement systems.

For example, the annual cost of the proposed requirement for a marginal-volume FMP is calculated as follows:

- 18,724 EGMs (from Table A.2) x -3 calibrations per year x $80 per calibration = ($4.49 million)
- 2,774 mechanical recorders (from Table A.2) x -2 calibrations per year x $80/calibration = ($444,000)
- **Total cost = ($4.49 million) + ($0.44 million) = ($4.93 million)** (*Note: Because marginal-volume FMPs would see a reduction in calibrations under the proposed rule that change would result in a cost reduction to industry*).

Table A.10 summarizes the cost of this proposed requirement. As shown in the table below, the BLM believes that the proposed rule would result in a cost benefit to industry since the majority of facilities BLM oversees are marginal- and low- volume (i.e., the facilities that will see a reduction in calibration frequencies).

Table A.10

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual Costs	One-time costs
Marginal-volume	(4.93)	0	(229)	0
Low-volume	(4.42)	0	(139)	0
High-volume	0.00	0	0	0
Very high-volume	0.57	0	638	0
Total	**(8.78)**	**0**		
Average			**(128)**	**0**

6. Uncertainty requirements

For very high-volume FMPs, the proposed rule would reduce the allowable uncertainty from ±3 percent under the current statewide NTLs for electronic flow computers, to ±2 percent (3175.30(2)). This could result in an operator having to replace the transducers or make other modifications to the FMP. Based on field experience, the BLM estimates that this requirement will affect 50 percent of very high-volume FMPs and that in 90 percent of those cases, the solution would be to install a smaller diameter orifice plate which costs about $35. In the remaining 10 percent of those cases, the solution would be to replace the transducer, typically with a transducer having a lower operating range. The BLM estimates this to cost $2,000, for a total cost of $103,000 (893 FMPs

[21] This estimate was based on the hourly rate of the personnel doing the calibration ($50) and on an estimate of one hour to perform the calibration. The BLM also estimated that drive time to and from the location would be $30 for a total cost per calibration of $80. While an EGM system generally takes less time to calibrate than a mechanical recorder, the BLM assumed the same time for all FMPs for purposes of this analysis.

x 50 percent x 10 percent x $2000/FMP, plus 893 FMPs x 50 percent x 90 percent x $35/FMP). Table A.11 summarizes these costs:

Table A.11

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0	0	0
Low-volume	0	0	0	0
High-volume	0	0	0	0
Very high-volume	0	0.1	0	112
Total	**0**	**0.1**		
Average			**0**	**2**

7. Replace chart recorders measuring more than 100 Mcf/day

Section 3175.90(a) of the proposed rule would prohibit the use of mechanical recorders on high- and very high-volume FMPs. Based on field experience, the BLM estimates that 10 percent of existing meters at these FMPs use mechanical recorders and 15 percent of those are measuring flow rates exceeding 100 Mcf/day.[22] The BLM also estimates that an EGM system would cost about $5,000 each, for a total cost of $5,151,300 (68,684 FMPs x 10 percent x 15 percent x $5000/EGM). The BLM does not believe that there are currently any mechanical recorders on very high-volume FMPs, therefore, the total cost of this requirement, summarized in Table A.12, was put in the "high-volume" category.

Table A.12

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual Costs	One-time costs
Marginal-volume	0	0	0	0
Low-volume	0	0	0	0
High-volume	0	5.2	0	357
Very high-volume	0	0	0	0
Total	**0**	**5.2**		
Average			**0**	**78**

8. Orifice plate and meter tube inspections

Orifice plate inspections

Order 5 requires that orifice plates be pulled and inspected at least once every 6 months, during the calibration of a meter. Section 3175.80(d) of the proposed rule would change this frequency for "routine inspections" as follows based on the flow category of a given FMP:

Flow Category	Proposed Orifice Inspection Frequency (months)	Change from Order 5 (inspections per year)
Marginal volume	12	-1
Low volume	6	0
High volume	3	+2
Very high volume	1	+10

[22] The vast majority of mechanical recorders in use at existing FMPs (85%) are used at marginal- and low- volume FMPs.

In addition, the proposed rule would require that an operator of an FMP measuring production from a newly-drilled well would have to pull and inspect the orifice plate every two weeks until the orifice plate that is pulled and inspected does not show any damage or wear. At that point the orifice plate inspection frequency would follow the frequency shown in the above table.

For exiting wells, based on current requirements, the BLM assumed that the orifice plate would be inspected during the calibration of the mechanical recorder or the EGM and would cost $60 per inspection.[23] For orifice plate inspections at FMPs measuring production from newly-drilled wells, the BLM assumed that the orifice plate would have to be inspected at a bi-weekly frequency three times until the plate showed no wear and the schedule could revert to that shown in the above table. Based on historical data, the BLM estimates that 3,000 new wells will be drilled each year. The BLM assumed that new wells would be distributed among the flow rate categories in the same proportion that existing wells are distributed (see Table A.1). Because these plate inspections would not generally be conducted at the same time as a meter calibration, transportation costs to conduct these inspections increases the total cost to $90 per inspection.

The total cost of the proposed orifice plate inspection requirements is the sum of the routine inspection and the inspections for FMPs measuring production from newly-drilled wells.

For example, the total cost of the new orifice plate inspection requirements for high-volume FMPs is as follows:

- *Cost of increased routine inspections*: 14,561 FMPs (from Table A.1) x +2 inspections per year x $60/inspection = $1.747 million
- *Cost of inspections for FMPs with newly-drilled wells*: 3,000 FMPs x 21.2% High-volume FMPs (from Table A.1) x 3 inspections x $90/inspection = $171,000;
- **Total cost: $1.747 million + $171,000 = $1.918 million**

The total costs associated with this proposed requirement are shown in Table A.13.

Table A.13

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	(1.04)	0	(48)	0
Low-volume	0.37	0	12	0
High-volume	1.92	0	131	0
Very high-volume	0.55	0	616	0
Total	**1.80**	**0**		
Average			**26**	**0**

Meter tube inspections

Order 5 currently has no requirements for meter tube inspections. The proposed rule would require both visual (3175.80(h)) and detailed meter tube inspections (3175.80(i)) at the frequency shown in Table A.14.

Table A.14

Flow Category	Proposed Visual Meter Tube Inspection Frequency (years)	Cost per Inspection per FMP ($)	Proposed Detailed Meter Tube Inspection Frequency (years)	Cost per Inspection per FMP ($)

[23] This cost assumes that the orifice plate would have to be replaced at a cost of $35. Changing an orifice plates generally takes less time than calibrating a meter and the cost of transportation to the site is already accounted for in the cost estimates for meter calibration; therefore, the labor cost for inspecting an orifice plate was estimated at $25 (30 minutes for a technician at $50/hour).

Flow Category	Proposed Visual Meter Tube Inspection Frequency (years)	Cost per Inspection per FMP ($)	Proposed Detailed Meter Tube Inspection Frequency (years)	Cost per Inspection per FMP ($)
Marginal volume	n/a			
Low volume	5	107		
High volume	2	143	10	1145
Very high volume	1	457	5	3656

The BLM assumed that the cost of performing a visual inspection would be $100 (one hour for two technicians each at $50/hour) plus the cost of the lost production while the FMP was shut down in order to perform the inspection. The cost of lost production assumed that the FMP would be shut in for one hour while the inspection was performed, that the flow rate for that hour was the average flow rate for each respective flow category shown in Table A.1, and that the value of the gas was $4/Mcf.   For example, the cost of lost production for a high-volume FMP is calculated as follows:

- 1 hour x 259 Mcf/day (from Table A.1) x $4/Mcf ÷ 24 hours/day = $43
- The total cost of the inspection is: $100 + $43 = 143

Based on discussion with companies that perform meter tube inspections, the BLM assumed that the cost of performing a detailed inspection would be $800 plus the cost of the lost production while the FMP was shut down in order to perform the inspection. The cost of lost production assumed that the FMP would be shut in for eight hours while the inspection was performed, that the flow rate for that hour was the average flow rate for each respective flow category shown in Table A.1, and that the value of the gas was $4/Mcf. The calculation is the same as presented in the above example, using 8 hours instead of 1 hour. The total cost of the proposed visual and detailed inspections is shown in the Table A.15 (a sample calculation follows the table):

Table A.15

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0	0	0
Low-volume	0.68	0	21	0
High-volume	2.71	0	188	0
Very-high-volume	1.06	0	1,187	0
Total	**4.45**	**0**		
Average			**65**	**0**

For example, the total cost for high-volume FMPs was calculated as follows:

- *Cost of visual inspection*: 14,561 FMPs (from Table A.1) x 0.5 inspections per year x $143/inspection = $1.04 million
- *Cost of detailed inspection*: 14,561 FMPs (from Table A.1) x 0.1 inspections per year x $1145/inspection = $1.67 million
- **Total cost of meter tube inspections: $1.04 million + $1.67 million = $2.71 million.**

9. Meter tube and thermometer well requirements

The proposed rule (3175.80) would include a number of new requirements for meter tubes and thermometer wells, including:

- All meter tubes at FMPs would have to comply with the latest API standards for minimum lengths and tube bundle placement (3175.80(k));
- 7-tube bundles would no longer be allowed (3175.80(f));
- Thermometer wells would have to be located in same ambient temperature environment as the orifice plate (3175.80(l)); and
- Continuous temperature would have to be recorded at all FMPs flowing more than 15 Mcf/day (3175.91(c) for mechanical records and 3175.101(e) for EGM systems); Order 5 does not require continuous temperature recording for meters measuring less than 200 Mcf/day.

Minimum meter tube lengths

Onshore Order 5 requires all sales and allocation meters to comply with the meter tube standards in AGA Report Number 3 (1985). The meter tube standards in the AGA report include minimum required lengths of straight pipe both upstream and downstream of the orifice plate. The standard also includes requirements pertaining to the location of the tube bundles, if used. In 2000, AGA[24] revised the minimum required lengths of meter tubes based on additional research. The new standards generally require longer meter tubes than the standards in the 1985 AGA report. The new standards also revised the location where tube bundles, if used, must be placed.

The BLM estimates that 5 percent of all FMPs, or 3,434 existing meters would have to be retrofitted to meet the new API standards incorporated by this rule. The BLM believes the average cost to retrofit a meter tube would be $800, for a total of $2.75 million. This cost was distributed among low-, high, and very high-volume FMPs proportionally using the number of FMPs in each category given in Table A.1. The proposed rule adopting the new API standards would not apply to marginal-volume FMPs. Table A.16 summarizes this cost by flow rate category.

Table A. 16

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0	0	0
Low-volume	0	1.85	0	58
High-volume	0	0.84	0	58
Very high-volume	0	0.05	0	58
Total	**0**	**2.74**		
Average			**0**	**40**

Elimination of 7-tube bundles

AGA Report No. 3 (1985), which is incorporated by reference in Onshore Order 5, allows the use of tube bundles. While the 1985 AGA report includes design standards for tube bundles, it does not specify the number of tubes that a tube-bundle can contain[25]. For 2-inch meters utilizing tube bundles, the tube bundles almost

[24] The proposed rule references API standards; however, the AGA and API standards are identical.
[25] By inference, the minimum number of tubes required in the 1985 AGA Report is 4

always consist of 7 tubes. 2-inch meter runs are most commonly found on meters flowing less than 1000 Mcf/day.

The proposed rule would adopt the latest API standards on tube bundle design, which specifically requires the tube bundle to contain 19 tubes. Because 19-tube bundles are rarely found in 2-inch meter runs, these meter tubes would have to be retrofitted. Based its field experience, the BLM estimates that 5 percent of all FMPs, or 3,434 existing meters, would have to be retrofitted as a result of this requirement. The most likely retrofit would be to replace the 7-tube bundles with isolating flow conditioners which cost about $250 for a 2-inch model. The total cost of this retrofit would be $858,000. This cost was distributed among low- and high-volume FMPs in proportion to the number of FMPs shown in Table A.1. The cost was not proportioned to marginal-volume FMPs because they are exempt from this requirement. The cost was not proportioned to very high-volume FMPs because most FMPs in this category have meters that are bigger than 2 inches. Table A.17 summarizes this cost by flow rate category.

Table A.17

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0	0	0
Low-volume	0	0.59	0	18
High-volume	0	0.27	0	18
Very high-volume	0	0	0	18
Total	**0**	**0.86**		
Average			**0**	**13**

New thermometer well requirements

Onshore Order 5 incorporates the requirements of AGA Report No. 3 (1985), which includes standards for the location of thermometer wells. The requirements for thermometer well location in the latest API standard that would be incorporated by reference in the proposed rule are the same as in the 1985 standard. However, the proposed rule would include several new requirements for thermometer wells on low-, high-, and very high-volume FMPs. The first requirement would be that the thermometer well would have to be located in the same ambient temperature environment as the primary device. This may require the operator to relocate the thermometer well. The BLM estimates that the cost to relocate a thermometer well is $200 (see discussion under “sample probe design and placement”) and that one-third (33%) of all existing low-, high-, and very high-volume FMPs, or 15,729 meters would have to be retrofitted, for a total cost of $3.19 million. This cost was distributed to the low-, high-, and very high-volume categories in proportion to the number of FMPs in each category (see Table A.1). Table A.18 summarizes the cost of the requirement by flow rate category.

Table A.18

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0	0	0
Low-volume	0	2.15	0	68
High-volume	0	0.98	0	68
Very high-volume	0	0.06	0	68
Total	**0**	**3.19**		
Average			**0**	**46**

Continuous temperature recorders required above 15 Mcf/day

Onshore Order 5 exempts meters measuring less than 200 Mcf/day from having a continuous temperature recorder. The proposed rule would lower the exemption threshold to 15 Mcf/day, thereby requiring a thermometer well, thermometer, and recording device for those FMPs that do not currently have one. Based on field experience, the BLM estimates that 3 percent of FMPs (primarily with mechanical recorders) do not have a continuous temperature recorder. The BLM also estimates that the cost to install a thermometer well, thermometer, and recording device would be about $1,300, for a total cost of $2.74 million. This cost was distributed to each low-, high-, and very high-volume flow category in proportion to the number of FMPs in each category as shown in Table A.1. Table A.19 summarizes the cost of this requirement by flow rate category:

Table A.19

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual Costs	One-time costs
Marginal-volume	0	0	0	0
Low-volume	0	1.85	0	58
High-volume	0	0.84	0	58
Very high-volume	0	0.02	0	58
Total	**0**	**2.71**		
Average			**0**	**40**

10. Reporting "dry" heating value

The proposed rule (3175.126(a)(1)) would require all heating values to be reported under the assumption that no water vapor is present (i.e. "dry'), unless the water vapor content has been determined through actual on-site measurement and reported on the gas analysis report. Order 5 has no requirements for the reporting of heating value and some operators report heating value under the assumption that water vapor is present (i.e. "wet" or "saturated"). Reporting heating value as "wet" or "saturated" reduces the heating value of the gas, and the resulting royalty, by 1.74 percent as compared to the heating value reported as "dry". The "wet" or "saturated" heating value assumes the gas is saturated with water vapor at 60°F and 14.73 psi, regardless of the actual temperature and pressure at the meter. Under the so-called "wet" or "saturated" conditions, water vapor occupies 1.74 percent of the gas volume. Because water vapor has no heating value, this assumption lowers the heating value of a gas by 1.74 percent.

Based on production audits, the BLM estimates that 45 percent of all heating values are currently reported under the "wet" or "saturated condition". According to the ONRR statistical information website, a total of $1.32 billion in royalty on gas production was paid to the Federal government and Indian tribes in FY2014. If all FMPs reported heating value on a "dry" basis, the increase in royalty would be the total royalty ($1.3 billion) multiplied by 45 percent multiplied by 1.74 percent, or $10.2 million. For this calculation, the BLM assumed that the increase in royalty would apply equally to all flow rate categories using the proportion of total volume each flow rate category contributes (see Table A.1). Table A.20 summarizes these costs.

Table A.20

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0.21	0	10	0
Low-volume	1.98	0	63	0
High-volume	5.29	0	371	0
Very-high-volume	2.71	0	3,067	0

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Total	**10.19**[26]	**0**		
Average			**150**	**0**

11. On-site data for mechanical recorders

Onshore Order 5 has no requirements for the data that must be on-site and available to BLM inspectors for mechanical recorders. The proposed rule (3175.91(d)) would add a requirement that certain data must be present on-site for all FMPs utilizing a mechanical recorder. The BLM estimates that 10 percent of all FMPs use mechanical recorders and the cost to provide the on-site data would be $40 per FMP, for a total cost of $275,000 (68,684 FMPs x 10% x $40/FMP). These costs were distributed among marginal- and low-volume FMPs based on the number of FMPs shown in Table A.1. The proposed rule would prohibit mechanical recorders on high- and very high-volume FMPs; therefore, no costs were distributed to those flow categories. Table A.21 summarizes these costs by flow rate category.

Table A.21

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0.11	0	36
Low-volume	0	0.16	0	36
High-volume	0	0	0	0
Very high-volume	0	0	0	0
Total	**0**	**0.27**		
Average			**4**	**0**

12. Requirements for manifolds and gauge lines

The proposed rule (3175.91(a) for mechanical recorders and 3175.101(a) for electronic gas measurement systems) would require standards for gauge lines and manifolds such as minimum diameter, maximum length, slope, and material of construction. Order 5 does not have any requirements relating to manifolds and gauge lines. Based on field inspections, the BLM estimates that this change would affect approximately 20 percent of existing mechanical recorders at low-volume FMPs, and 5 percent of existing electronic gas measurement systems. The BLM also estimates that the cost of retrofitting gauge lines would require 3 hours of work at $50/hour, or $150. The costs of this requirement were calculated as follows:

- Cost for mechanical recorders: 68,684 FMPs x 10% mechanical recorders x 20% x $150 = $206,000
- Cost for EGM systems: 68,684 FMPs x 90% EGM systems x 5% x $150 = $463,000
- Total cost: $206,000 + $463,000 = $669,000

This cost was distributed among low-, high-, and very high-volume FMPs in proportion to the number of FMPs in each category shown in Table A.1. Marginal-volume FMPs were not included because they would be exempt from this requirement. The total costs by flow rate category are summarized in Table A.22:

[26] The projected increase in royalty is a transfer payment and is not considered a direct cost to operators; therefore, it is not included in the total costs, but accounted for separately.

Table A.22

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	**One-time costs**	**Annual costs**	**One-time costs**
Marginal-volume	0	0	0	0
Low-volume	0	0.21	0	7
High-volume	0	0.43	0	30
Very high-volume	0	0.03	0	30
Total	**0**	**0.67**		
Average			**0**	**10**

13. New EGM calibration requirements

Because Order 5 only applies to mechanical recorders, it does not contain any requirements for the calibration of EGM systems. The statewide NTLs for electronic flow computers have requirements for EGM systems; however, these requirements are based on the requirements for mechanical recorders in Order 5 and are limited to calibration frequency, calibration tolerance, and the points which must be verified.

The proposed rule would establish new calibration requirements for EGM systems:

- The practice of using resistor or "decade" boxes to verify and calibrate the temperature transducer would be prohibited (3175.102(c));
- The differential pressure transducer would have to be verified at both working pressure zero and atmospheric pressure zero (3175.102(c)); and
- Recertification of test equipment would be required (3175.102(h)(1)).

Temperature transducer verification

The proposed rule (3175.102) would prohibit the use of resistor or decade boxes when verifying or calibrating an EGM system. When verifying the temperature readings of an EGM system, it is common practice to disconnect the RTD (the temperature sensing element) from the flow computer or temperature transducer and apply "simulated" temperatures to the flow computer or temperature transducer in place of the RTD. The simulated temperatures are generated by resistors that are often referred to as a "decade box". The problem with this method is that errors in the RTD or the connections between the RTD and flow computer or temperature transducer will not be detected during the verification. The prohibition would ensure the RTD and RTD connections are also checked which could increase the number of RTDs or RTD connections that must be repaired or replaced. Based on field inspections, the BLM estimates that the RTDs on one percent of all FMPs will need to be replaced as a result of this proposed requirement. The BLM also estimates that the cost of an RTD is $500 for a total one-time cost of $215,000. This requirement does not apply to marginal-volume FMPs because marginal-volume FMPs are not required to measure temperature continuously.

These costs are not distributed in proportion to the number of FMPs in each category in Table A.1 because all mechanical recorders would be in the marginal- and low-volume categories under the proposed rule. Therefore, the proportion of EGM systems in these categories is lower than it would be for the high- and very high-volume FMPs. The distribution for any requirement relating to EGM systems would be as shown in Table A.23.

Table A.23. Distribution of EGM Systems by Flow Category

FMP Category	No. of FMPs	No. of mechanical recorders	No. of EGM systems	% of EGM systems
Marginal-volume	21,498	2,774	18,724	29.8
Low-volume	31,732	4,094	27,638	44.0
High-volume	14,561	0	14,561	24.8

FMP Category	No. of FMPs	No. of mechanical recorders	No. of EGM systems	% of EGM systems
Very high-volume	893	0	893	1.4
Total	68,684	6,868	61,816	100.0

For example, the distribution of this cost to low-volume FMPs is done as follows: 27,638 x 1% x $300 = $83,000. Table A.24 summarizes the cost associated with the temperature transducer verification requirement by flow category:

Table A.24

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0	0	0
Low-volume	0	0.14	0	4
High-volume	0	0.07	0	4
Very high-volume	0	0.004	0	4
Total	**0**	**0.21**		
Average			**4**	**0**

Working pressure zero verification of differential pressure transducers

Order 5 has no requirements related to working pressure zero verification. However, current statewide Notice to Lessees (NTLs) for electronic flow computers require that the differential pressure transmitter be verified at zero, 100 percent of its calibrated span, and at one point that represents the normal flowing reading of the transmitter.[27] The proposed rule (3175.102) would require the operator to also obtain a zero differential pressure reading at working pressure during a calibration.[28] This requirement would apply to the calibration of all EGM systems and would increase the cost of verification/calibration by an estimated $15 per calibration. Based on the proposed verification frequency, the total number of verifications for EGM systems is shown in Table A.25

Table A. 25

Flow Category	Proposed Verification Frequency (verifications per year)	No. of EGM systems	No. of Verifications per Year
Marginal volume	1	18,724	18,724
Low volume	2	27,638	55,276
High volume	4	14,561	58,244
Very high volume	12	893	10,716
TOTAL		**61,692**	**142,960**

The cost of this requirement for each flow rate category is the number of verifications required under the proposed rule per year times the estimated cost of $15 per verification. These costs are summarized in Table A.26.

Table A.26

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0.28	0	13	0

[27] To verify the zero point, both the high and low side of the transmitter are vented to the atmosphere.

[28] This would be accomplished by equalizing the high and low side of the transducer under line pressure. The proposed rule would also require that the difference between the working pressure zero and the zero obtained with both sides vented to atmosphere be applied to all the verification points required.

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Low-volume	0.83	0	26	0
High-volume	0.87	0	60	0
Very-high-volume	0.16	0	179	0
Total	**2.14**	**0**		
Average			**31**	**0**

Recertification of test equipment

Neither Order 5 nor the existing statewide NTLs for electronic flow computers have explicit requirements relating to the test equipment used to calibrate transmitters. The proposed rule (3175.102) would require that test equipment used to verify and calibrate EGM systems be recertified at least every two years. The BLM estimates that one calibration gauge would be used to perform 50 verifications per year. Dividing the total number of verifications from the above table (142,960) by the number of verifications per year (50), would require 2,800 test gauges to be in service. Under the proposed rule's every two year certification, we assume that half of these gauges would have to be recertified every year at an estimated cost of $700 per recertification. The total annual cost of this requirement would be $980,000.

This cost is distributed to each flow rate category in proportion to the number of verifications that would be required per year, as shown in the table above. These costs are summarized in Table A.27:

Table A.27

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0.13	0	6	0
Low-volume	0.38	0	12	0
High-volume	0.40	0	27	0
Very-high-volume	0.07	0	78	0
Total	**0.98**	**0**		
Average			**14**	**0**

14. EGM Requirements for Logs and Calculations

The proposed rule would require a number of changes relating to how EGM systems calculate flow rate and establish an audit trail relative to the current requirements of Order 5. The two most significant one-time costs would be to retrofit EGM systems to use the new gas expansion factor required by API MPMS 14.3.3., and to retrofit data acquisition equipment to retrieve the integral value[29]. The most significant annual cost would be a result of proposed 3175.104, which would require that only original, unprocessed, unaltered, and unedited data be submitted to the BLM during a production audit. Submitting such data could require additional work by operators because it may require operators to access records directly from the EGM system without going through third party software, which is the current operation practice. It should be noted, as explained below, not every FMP is subject to a production audit every year.

New gas expansion factor

[29] The "integral value" is a number generated by the flow computer from raw data that can be used to independently recalculate and verify reported volumes.

The proposed rule (3175.103(a)(1)) would require operators to use the gas expansion factor in API 14.3.3. The BLM estimates that the cost to upgrade EGM software to use the new gas expansion factor would average about $40 per FMP for a total cost of $2.5 million. These costs are distributed to each flow category in proportion to the number of EGM systems shown in Table A.2. Table A.28 summarizes these costs by flow category:

Table A.28

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0.75	0	35
Low-volume	0	1.11	0	35
High-volume	0	0.58	0	40
Very high-volume	0	0.04	0	40
Total	**0**	**2.48**		
Average			**0**	**36**

New audit trail requirements

The proposed rule (3175.104(a)(2)) would require operators to include the integral value in the quantity transaction record. The BLM estimates that operators of 8 percent of existing FMPs using EGM systems do not currently gather or report the integral value. The BLM also estimates that the cost to upgrade data acquisition or software to collect and report the integral value would cost about $200 per FMP, for a total cost of $989,000. These costs are distributed to each flow category in proportion to the number of EGM systems shown in Table A.2. Table A.29 summarizes these costs by flow category:

Table A.29

FMP Category	Total Cost ($millions)		Cost per FMP ($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0	0.30	0	14
Low-volume	0	0.45	0	14
High-volume	0	0.23	0	16
Very high-volume	0	0.01	0	16
Total	**0**	**0.99**		
Average			**0**	**14**

Reporting original data

The proposed rule (3175.104(a)) would require operators to report "original, unaltered, unprocessed, and unedited" data to the BLM upon request, generally during a production audit. The BLM estimates that the cost of providing this data for BLM would be $400 per FMP more than the cost of providing processed or edited data from third party software packages. The BLM audits about 1000 cases per year and, on average, each case consists of 3 FMPs for a total annual cost of $1.2 million (1000 cases x 3 FMPs per case x $400 per FMP). These costs are distributed to each flow category in proportion to the number of EGM systems in each flow category as shown in Table A.2. Table A.30 summarizes these costs by flow category:

Table A.30

FMP Category	Total Cost ($millions)		Cost per FMP($)	
	Annual costs	One-time costs	Annual costs	One-time costs
Marginal-volume	0.38	0	17	0
Low-volume	0.55	0	17	0

FMP Category	Total Cost ($millions)		Cost per FMP($)	
	Annual costs	One-time costs	Annual costs	One-time costs
High-volume	0.25	0	17	0
Very high-volume	0.02	0	17	0
Total	**1.20**	**0**		
Average			**17**	**0**

15. Revisions to Civil Penalty Assessments

The BLM does not estimate that the revisions to civil penalty assessments proposed in this rule would result in any costs to operators, because the BLM presumes compliance for purposes of this economic impact analysis.

Appendix B
SEC Small Entity Data

		Reported			**Reported**			**Calculated**			**Net Income ($ in 1000s)**			**Profit Margin (%)**			**Difference in**		
		Total Revenue ($ in 1000s)			**Net Income ($ in 1000s)**			**Profit Margin (%)**			**with cost increase**			**with cost increase**			**Profit Margin (%)**		
Company	**Number of Employees**	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
A	444	2720632	1313134	735718	673587	-18930	-285069	25%	-1%	-39%	673574	-18943	-285082	25%	-1%	-39%	0.0005%	0.0010%	0.0018%
B	384	795542	974179	951489	-189543	117634	149426	-24%	12%	16%	-189556	117621	149413	-24%	12%	16%	0.0016%	0.0013%	0.0014%
C	15	1558758	1983388	1934642	253285	-553889	141571	16%	-28%	7%	253272	-553902	141558	16%	-28%	7%	0.0008%	0.0007%	0.0007%
D	75	793885	665257	583894	265573	118000	61654	33%	18%	11%	265560	117987	61641	33%	18%	11%	0.0016%	0.0020%	0.0022%
E	293	569428	561562	709038	-103100	161618	-2352606	-18%	29%	-332%	-103113	161605	-2352619	-18%	29%	-332%	0.0023%	0.0023%	0.0018%
F	159	298204	197372	231315	-139907	-277979	-150602	-47%	-141%	-65%	-139920	-277992	-150615	-47%	-141%	-65%	0.0044%	0.0066%	0.0056%
G	300	532299	485489	346460	-283645	-35272	68637	-53%	-7%	20%	-283658	-35285	68624	-53%	-7%	20%	0.0024%	0.0027%	0.0038%
H	225	616207	355792	319299	99200	-153715	-95875	16%	-43%	-30%	99187	-153728	-95888	16%	-43%	-30%	0.0021%	0.0037%	0.0041%
I	158	224209	317502	356516	120437	14319	-46587	54%	5%	-13%	120424	14306	-46600	54%	5%	-13%	0.0058%	0.0041%	0.0036%
J	247	710187	520182	368180	226343	43683	55487	32%	8%	15%	226330	43670	55474	32%	8%	15%	0.0018%	0.0025%	0.0035%
K	202	472291	568093	700195	15081	-192733	582	3%	-34%	0%	15068	-192746	569	3%	-34%	0%	0.0028%	0.0023%	0.0019%
L	123	133776	92324	65664	63269	38647	-18791	47%	42%	-29%	63256	38634	-18804	47%	42%	-29%	0.0097%	0.0141%	0.0198%
M	334	558633	421860	231205	20283	69184	46523	4%	16%	20%	20270	69171	46510	4%	16%	20%	0.0023%	0.0031%	0.0056%
N	27	44089	35319	38165	-7585	-13073	-10327	-17%	-37%	-27%	-7598	-13086	-10340	-17%	-37%	-27%	0.0295%	0.0368%	0.0341%
O	21	13840	17438	16243	2884	8612	38074	21%	49%	234%	2871	8599	38061	21%	49%	234%	0.0939%	0.0745%	0.0800%
P	11	12679	8029	2264	-34510	3855	-538	-272%	48%	-24%	-34523	3842	-551	-272%	48%	-24%	0.1025%	0.1619%	0.5742%
Q	70	13208	13547	12106	3205	3542	3659	24%	26%	30%	3192	3529	3646	24%	26%	30%	0.0984%	0.0960%	0.1074%
R	419		999506	248322		-1222662	-53885		-122%	-22%		-1222675	-53898		-122%	-22%		0.0013%	0.0052%
S	2	12352	13126	14781	-2464	3353	-2359	-20%	26%	-16%	-2477	3340	-2372	-20%	25%	-16%	0.1052%	0.0990%	0.0880%
T	57	171418	87755	49940	50953	49342	-153791	30%	56%	-308%	50940	49329	-153804	30%	56%	-308%	0.0076%	0.0148%	0.0260%
U	20	3221	2573	2366	-2152	1149	-13691	-67%	45%	-579%	-2165	1136	-13704	-67%	44%	-579%	0.4036%	0.5052%	0.5495%
V	29	104219	46223	24969	28853	9581	12124	28%	21%	49%	28840	9568	12111	28%	21%	49%	0.0125%	0.0281%	0.0521%
W	105	208553	203295	180845	-353136	-95186	-84202	-169%	-47%	-47%	-353149	-95199	-84215	-169%	-47%	-47%	0.0062%	0.0064%	0.0072%
X	440	391469	304538	159937	-143474	-222176	-132708	-37%	-73%	-83%	-143487	-222189	-132721	-37%	-73%	-83%	0.0033%	0.0043%	0.0081%
Y	164	636773	431468	317149	-409592	-143970	-104589	-64%	-33%	-33%	-409605	-143983	-104602	-64%	-33%	-33%	0.0020%	0.0030%	0.0041%
Z	374	1431289			22665			2%			22652			2%			0.0009%		
Average	181	521086	424758	344028	7060	-91483	-117115	-18%	-7%	-50%	7047	-91496	-117128	-18%	-7%	-50%	0.0362%	0.0431%	0.0637%

Source: U.S. Securities and Exchange Commission (http://www.sec.gov/search/search.htm)